Australian Energy Market Commission

REVIEW

STAGE 1 FINAL REPORT

East Coast Wholesale Gas Market and Pipeline Frameworks Review

23 July 2015

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Stage 1 Final Report

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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 eastern Australian gas market is experiencing a period of significant growth and change, as conventional gas reserves decline, unconventional gas resources become increasingly important and the influence of international prices trends increases. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering unprecedented shifts in supply and demand and, consequently, changes in patterns of gas flows. These factors are resulting in a renewed focus on market development and gas supply chain efficiency.

Against this background, the COAG Energy Council has 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 review is to consider the role and objectives of the existing markets on the east coast in light of the changing market dynamics and set out a road map for their continued development. The Energy Council has developed a Vision for gas market development and a Gas Market Development Plan that will guide the scope of this review.

The Energy Council, at the request of the Victorian Government, has 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"). At this stage, we are incorporating analysis of the DWGM within the East Coast Review but during the second half of 2015 the DWGM Review will form its own workstream.

The focus of the reviews is therefore 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 AEMC's remit and are being considered by other bodies, which we intend to work and consult with closely given the complementarity of the analysis. In particular, the Australian Competition and Consumer Commission (ACCC) has been tasked with undertaking an inquiry into Eastern and Southern Australian wholesale gas prices.

The East Coast Review has been structured over two stages. Stage 1 outlines the overall direction for the east coast market development, including a factbase of current market outcomes and gap analysis between the Energy Council's Vision and the existing arrangements. Stage 2 will more fully develop any necessary medium and long term adjustments required to implement the Vision, including the transition path required. This structure is designed to provide the Energy Council with early and ongoing insight into the progress being made on the development and implementation of their reform agenda in this important area.

This report is the AEMC’s Stage 1 Final Report and contains our preliminary recommendations on the areas of focus for market reform to be pursued in Stage 2, as well as recommendations for market enhancements and initiatives that can be progressed in the near term.

Changing market dynamics and the need for reform

Historically, natural gas has been used for a range of industrial, commercial and domestic applications in eastern Australia. Large industrial use makes up the largest share of total gas demand in eastern Australia overall, accounting for 44 per cent of demand in 2014. Gas-fired generation is responsible for approximately one-third of demand, most of which is base load generation in Queensland and South Australia. Residential and commercial demand makes up a relatively small amount of demand in all states besides Victoria (and to a lesser extent, New South Wales), where it comprises over half of total demand.[1]

In an emerging market, with a handful of suppliers and customers, remote production facilities and pipelines had little alternative use if a buyer was to terminate its agreement to purchase the output of those assets. Long-term contracts were therefore implemented to reduce the risks and costs for both sellers and buyers of gas. In a small, stable market where transactions occurred infrequently, finding counterparties and undertaking negotiations was relatively straightforward.

The development of the LNG industry, combined with the growing maturity of the east coast market, is expected to fundamentally alter these market dynamics. While bilateral contracts are likely to remain a fixture of the east coast markets in the future, industry participants are also likely to require more flexible and sophisticated mechanisms to manage their gas portfolios. However, in the current environment a number of large users have reportedly found it difficult to find producers that are willing to enter into new long term contracts, or contracts of sufficient length to meet their commercial needs and support investment. Concerns have also been raised by some users about the prices payable under new contracts.

The current facilitated markets in eastern Australia (the DWGM, the Short Term Trading Market (STTM) hubs and the Wallumbilla Gas Supply Hub) were intended to provide additional market options to complement the trade of wholesale gas through bilateral contracts and to allow greater transparency and improved price discovery.

However, it is not clear that the DWGM and the STTM are meeting this objective or are likely to provide the flexibility required under this new market dynamic. In particular, the requirement for all gas in these markets to be traded through them, despite the vast majority of transactions occurring through bilateral contracts outside of the markets, imposes additional direct and indirect costs on shippers. The markets can also expose participants to a number of price risks, for instance as a result of deviating from their scheduled positions, some of which may be difficult or impossible to manage.

A drawback of the prevalence of bilateral contracting for gas is that little price information is publicly available. This lack of transparency can impede the price discovery process. This is currently a particular concern to users as the market transitions to prices driven by the ability to export gas, and consequently influenced by international LNG prices.

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1 AEMO, *National Gas Forecasting Report*, 2014.

The facilitated markets are however only part of the changing dynamic. There are substantial inter-linkages between transportation arrangements for gas and the facilitated markets for trading gas at demand and production centres. The full benefits of any further development of the markets are unlikely to be realised if gas cannot flow to where it is most highly valued.

Gas transportation arrangements on the east coast are characterised by a marked difference between those used in Victoria and those applying elsewhere. Under the Victorian arrangements, market outcomes in the DWGM determine the use of the pipeline system on a daily basis. Elsewhere, pipeline owners enter into bilateral contracts with their customers to allocate pipeline capacity, generally over long periods.

Bilateral contracting for gas transportation has facilitated significant new investment, with the Australian Pipelines and Gas Association (APGA) reporting that its members have built over $2.2 billion of new infrastructure providing 4000km of coverage across a large number of new gas transmission pipelines since 2000.[2]

However, the significant increases in demand and the volatility of flows likely to be experienced on the transmission network in the future will test the flexibility of the current arrangements. As an example, the outage of a single LNG facility could lead to the redirection of gas equivalent to a significant proportion of total domestic demand. There are concerns that, under such circumstances, difficulties in reallocating rights to use pipelines will impede the ability of the market to reach an efficient outcome.

Directions for Stage 2 and the treatment of medium to long term issues

The market and regulatory frameworks impacting Australia's gas markets have evolved in a somewhat piecemeal manner since the development of the initial gas access regime in the 1990s. Consequently, fully understanding the issues and developing and assessing potential solutions requires detailed analysis and consultation with industry.

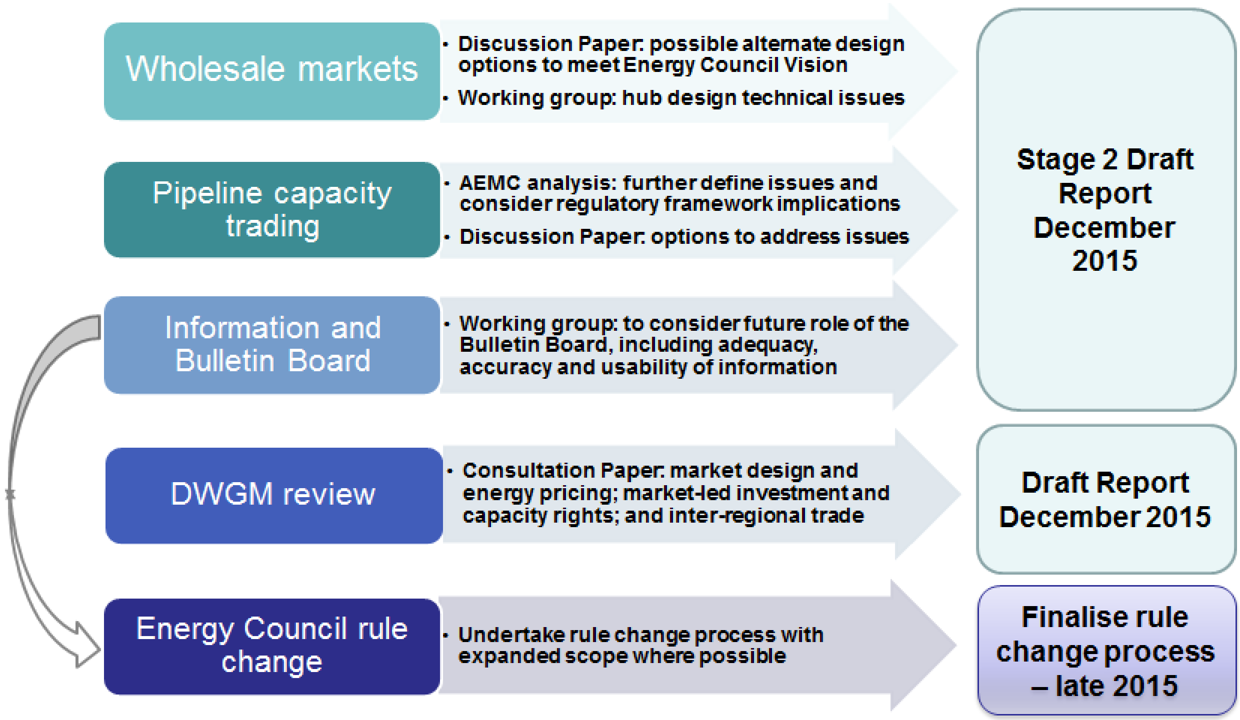
Stage 2 of the review is intended to allow for the development of any medium and long term adjustments necessary to implement the Energy Council's Vision. Many of the issues that we have identified in Stage 1 of the review fall into this category, with it being possible to address only relatively few issues through incremental changes that can be made immediately.

In order to define the long term roadmap for market development, we intend to progress the potential medium and longer term reform requirements in Stage 2 of the review through four main workstreams, as shown in Figure 1.[3]

2 APGA, Discussion Paper submission, p. 4.

3 Figure 1 also includes the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change proposed by the COAG Energy Council.

Figure 1 Stage 2 Workstreams



Wholesale markets

The Energy Council's Vision clearly outlines a desire for the development of an efficient reference price. Given their design and location, we consider it questionable whether delivery of efficient reference prices is likely to be a realistic expectation of the STTM hubs. The STTM is trying to achieve multiple objectives and, as a result, is relatively complex and costly. The main function played by the STTM is a balancing market, although a number of stakeholders, particularly large users, have also highlighted the value they derive from being able to use the STTM as a supplement to bilateral contracting for gas supplies.

Consequently, we intend to consider what the objectives of the STTM should be, and whether it would be possible to simplify the design while still meeting these objectives. This will be important in allowing us to develop a longer term plan for the development of the facilitated markets on the east coast.

To commence this work, we intend to publish a Discussion Paper for consultation in early August 2015 that will outline the characteristics of different gas market designs and potential structures that could be implemented to meet the Energy Council's Vision. A working group comprised of industry and user representatives will also be established to provide the Commission with expert technical advice as it finalises its recommended approach for the Stage 2 Draft Report in December 2015.

Through this process we will work closely with the Australian Energy Market Operator (AEMO) as it progresses its work to further develop the design of the Wallumbilla Gas Supply Hub (GSH). We will consider the interaction between the STTM and commodity trading at current and potential GSH locations, and will also consider broader questions, such as whether trade should be at specific physical locations or at "virtual" points encompassing parts or all of the pipeline network. We will investigate the scope for increasing the consistency in gas market designs across the east coast to minimise transaction costs, where possible. Finally, we will also consider implementation and transitional issues, such as whether there would be merit in trialling a simplified market design at Brisbane.

It is in this context that consideration needs to be given to the potential introduction of a GSH location at Moomba. Although we see some merit in this, given Moomba's status as a production centre linked to multiple pipelines, there is a need to consider how and when it might best fit into the wider east coast market. While a number of stakeholders have expressed support for Moomba, many have done so in the context of considering Moomba's likely role in the broader development of the market.

Pipeline capacity trading

Based on our Stage 1 analysis, the submissions we have received and observations from earlier reviews, it appears that there are some aspects of the pipeline arrangements used outside of Victoria which impede the efficiency with which capacity rights are reallocated and used.

These issues are complex and will require more detailed analysis than has been possible to achieve in Stage 1 of the review. A major element of our Stage 2 work will therefore be to investigate and consider potential measures to better facilitate pipeline capacity trading.

We intend to initially undertake further work to define the issues or barriers to trading, before developing and assessing options to address these. In particular, we intend to examine and potentially draw on approaches to this issue used in international markets in Europe and North America (to the extent that they might be applicable to Australian circumstances). To this end, we have commissioned Market Reform to undertake a study of International Gas Markets, which has been published alongside this report.

As part of this more detailed work, we will consider whether the existing regulatory framework is likely to remain fit for purpose given the changes underway in the market and whether changes to this framework (including the third party access regime) would be required to improve the efficiency with which pipeline capacity is allocated and reallocated.

Information provision and the Bulletin Board

In our work to date, it has become clear that informational sources on the eastern Australian gas market are fragmented and somewhat under-developed by international standards. Consequently, in Stage 2 of the review, we intend to consider the strategic direction for information provision, particularly the development of the Bulletin Board.

To progress this, we propose to form a Bulletin Board technical working group, which will be comprised of representatives from industry, governments and market bodies. The group will consider potential further development of the Bulletin Board, but will also re-examine the structure underpinning it, for instance which pipelines are included and its ability to accommodate bidirectional pipelines.

We will develop a structured workplan for the working group which will cover issues such as: Bulletin Board coverage and registration; the presentation and usability of data; the timeliness and reliability of information; enforcement and compliance; and governance. The group will also consider whether the benefits of any informational improvements are likely to exceed the costs, and will provide its assessment back to the AEMC to be considered as part of our Stage 2 recommendations.

Separately, the Commission also intends to consider whether there are any informational gaps that fall within the scope of the COAG Energy Council's Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and that could therefore be dealt with in a more timely manner through this process. This is discussed further below.

DWGM review

As noted above, the Commission has been provided with an additional terms of reference specifically to undertake a detailed review of the DWGM. Over the second half of 2015 we intend to progress this as a standalone review, although there will be important linkages to the East Coast Review.

Through the DWGM Review we intend to consider whether the original objectives for the market in Victoria remain relevant in light of the changing broader east coast environment, and whether the current market design is achieving its objectives in an efficient manner.

A major area of focus for the DWGM Review will be to understand whether improvements can be made to the liquidity of trading and the pricing mechanism in the DWGM. In line with the Energy Council's Vision, we will consider the extent to which the DWGM can provide an efficient reference price and how this might be achieved. To do so may involve establishing whether energy prices can be separated from balancing and uplift charges, and assessing the effects of the current range of prices, including the intra-day rescheduling of the market. We will also consider the potential for harmonising the balancing element of the market with the design of the STTM and the commodity element with the GSH.

The other major element of this work will be to examine the potential to introduce capacity rights to the DWGM, with the objective of better facilitating market-led investment in network expansion. This would allow participants to signal the need for capacity augmentation, which would be likely to result in more efficient investment, and would transfer risk away from consumers to parties better able to manage it. The extent to which this facilitates inter-regional trade with adjoining markets will also be an important factor in our assessment.

We intend to commence this work with the publication of a paper for consultation in August/September 2015. This paper will further investigate the key areas of concern and clearly define the issues, as well as setting out some high level options for consideration. These options are likely to include incremental improvements, as well as more substantial changes such as those previously recommended for implementation by VENCorp[4] and options drawing on international experience.

Issues that can be progressed in the shorter term

The Commission has given consideration to a number of issues that can be progressed over the short-term to assist the facilitated markets and pipeline frameworks to better achieve the National Gas Objective (NGO). These comprise:

- improving price transparency through the introduction of a wholesale gas price index by the Australian Bureau of Statistics (ABS);
- harmonising the start time of the "gas day", which currently varies across jurisdictions;
- removing the limitation in the National Gas Law on who can submit DWGM rule changes; and
- assessing the degree to which additional informational gaps fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and could be addressed under that process.

The Commission is of the view that these "no-regrets" measures can be implemented without undermining the second stage of our work to develop the medium and long term adjustments required in the east coast markets and pipeline frameworks to implement the Energy Council's Vision.

Improving price transparency

While some information on wholesale gas prices is available in the market, we consider that greater transparency 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 is to work with the ABS to develop a survey-based gas price index that would measure the trends in prices payable under bilateral contracts over time.

This 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 bilateral gas contracts.

4 VENCorp previously operated the DWGM, and was one of the predecessor bodies to AEMO.

Given that the prices payable under gas contracts have historically been linked to Consumer Price Index (CPI), we would expect movements in the index to closely match movements in CPI in the early stages. However, as existing gas contracts roll off in the next one to two years and new contracts are negotiated and captured by the index, we would expect movements to reflect the pricing structures adopted in these new contracts, which may be linked to CPI and/or oil prices, increasing transparency for gas users.

The AEMC has already held initial discussions with the ABS about the introduction of such an index, and understands that it would be possible for the ABS to compile and publish this on an ongoing basis. The next step in implementing the index will be for the AEMC to facilitate a workshop between industry and the ABS to discuss the methodology, data collection process, confidentiality arrangements and other issues.

Subject to the successful resolution of these issues, and active support from industry, it may be possible to introduce the index from the December 2015 quarter release (for publication end of January 2016), potentially including retrospective data going back a number of years.

Harmonising the gas day start times

Trading of gas is conducted over "gas days", and the timing of these currently differs across the east coast.[5] Harmonising gas day start times may remove some of the complexity for parties that operate across multiple markets and assist the process of increasing the interoperability across all the facilitated markets. This would be likely to reduce transaction costs, and could therefore promote the NGO.

Submissions made to us in Stage 1 of the review have shown widespread support for such a change. Some parties have highlighted a number of one-off costs associated with implementing the change. However, it is also generally considered that these costs are likely to be less than the long term benefits that would result from a harmonised regime as the integration of the east coast market continues, although sufficient lead time would be required to implement necessary technical and contractual changes.

The nature of the Victorian market (in particular, the timing of reschedules in the DWGM) has led us to form a view that 6:00am would be most likely to minimise implementation costs, although few compelling arguments have been made as to what the harmonised start time should be. Consequently, we recommend that the Energy Council submit a rule change to the AEMC to change the gas day start time for the STTM hubs to 6:00am and to define the gas day start time for the GSH as 6:00am.[6] The assessment of the rule change request by the Commission will allow for further consultation on, and detailed consideration of, the exact gas day start time and the process for implementing this.

5 6:00am in Victoria, 6:30am at the Sydney and Adelaide STTM hubs, and 8:00am at the Brisbane STTM hub and Wallumbilla supply hub.

6 Consequential changes to the exchange agreement are therefore likely to be required to implement this change.

DWGM rule changes

Section 295(3)(a) of the National Gas Law (NGL) provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[7]

We note that this restriction was raised in both the 2013 Victorian Gas Market Taskforce review and the 2013 AEMC Gas Market Scoping study. In both reviews, stakeholders expressed concerns with the process of engaging with AEMO prior to a rule change being submitted. It was suggested that this represents a barrier for smaller market participants and potential new entrants to influence market development.

To address these issues, we recommend that the restriction be removed. All submissions made to this review addressing this issue have been supportive of this step. This would mean that any party would be able to propose rule changes applying to the DWGM, in a manner consistent with the arrangements applying to the STTM, as well as those applying to the electricity sector through the National Electricity Rules.

Addressing additional information gaps

As noted above, the Commission will shortly begin its assessment of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change proposed by the Energy Council. While the starting point for the Commission's assessment will be the Energy Council's rule change request, we also intend to consider whether there are any other informational gaps that fall within the scope of the proposed rule change that could also be dealt with at this time. This could provide an efficient and timely way of addressing information gaps that require changes to be made to the rules.

The Commission intends to release a consultation paper on the rule change later in July 2015. The paper will raise the possibility of including suggestions made by stakeholders for additional information, such as data on storage facilities and volumes, and data on linepack, as well as potential improvements to the medium-term capacity outlook information that Bulletin Board facilities are required to provide to AEMO.

7 Victoria is currently the only adoptive jurisdiction.

Table 1 East Coast Wholesale Gas Market and Pipeline Frameworks Review - Stage 1 Implementation Plan

Recommendation	COAG Energy Council action	Implementation
A bilateral gas contract price index should be produced by the ABS.	No action required.	AEMC to facilitate an industry workshop between the industry and the ABS to discuss methodology, data collection process, confidentiality issues and any other issues. Index to be implemented by the ABS from Q4 2015, if considered workable.
The gas day should be harmonised across all east coast markets.	COAG Energy Council to consider recommendation and submit a rule change request to the AEMC that changes the gas day start times for the STTM hubs to 6:00am, and defines the gas day start time for the GSH as 6:00am.	COAG Energy Council decision to support lodgement of rule change request and proposal to change the exchange agreement at its July 2015 meeting.
Section 295(3)(a) of the NGL should be deleted to allow any party to propose rule changes applying to the DWGM.	COAG Energy Council to develop changes to the NGL to: • delete section 295(3)(a); and • split out AEMO's functions relating to the operation and administration of the DWGM from its other declared system functions contained in section 91BA(1).	COAG Energy Council decision to support this recommendation at its July 2015 meeting and to agree a process for implementation.
Where consistent with the NGO, information gaps that would fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change should be progressed through the assessment process for that rule change request.	No action required.	AEMC to consider relevant issues and consult with stakeholders as part of the rule change process. AEMC to initiate rule change request in July 2015.

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1 Introduction

1.1 Context for the review

The eastern Australian gas market is experiencing a period of significant growth and change, as conventional gas reserves decline, unconventional gas resources become increasingly important and the influence of international prices trends increases. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering unprecedented shifts in supply and demand and, consequently, changes in patterns of gas flows. These factors are resulting in a renewed focus on market development and gas supply chain efficiency.

Against this background, the COAG Energy Council has 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 review is 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.[8]

The Energy Council, at the request of the Victorian Government, has 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").[9]

The focus of the reviews is therefore 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 AEMC's remit and are being considered by other bodies, which we intend to work and consult with.[10]

1.1.1 Gas markets and transportation are interlinked

The terms of reference for both reviews recognise the inter-linkages between transportation arrangements for gas and the facilitated markets for trading gas at demand and production centres. Accordingly, much of the Commission's work thus far has been to consider this interaction and to understand how transportation arrangements and the facilitated markets can best support the efficient allocation of gas. The full benefits of any further development of the markets are unlikely to be realised if gas cannot flow to where it is most highly valued.

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

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

10 In particular, on 8 April 2015, the ACCC was tasked with undertaking an inquiry into Eastern and Southern Australian wholesale gas prices. In addition, on 14 April 2015, the Australian Government released its *Domestic Gas Strategy* on unconventional gas resources.

Gas transportation arrangements on the east coast are characterised by a marked difference between those used in Victoria and those applying elsewhere. Under the Victorian arrangements, market outcomes in the DWGM determine the use of the pipeline system on a daily basis. Elsewhere, pipeline owners enter into bilateral contracts with their customers ("shippers") to allocate pipeline capacity, generally over long periods.

Through its direct linkage to the DWGM, the focus of the Victorian arrangements is therefore to promote the efficient use of the system in the short-term. However, the lack of firm capacity rights in the Declared Transmission System (DTS) has led to well-documented concerns with investment outcomes over the long-term.[11]

In contrast, bilateral contracting for gas transportation has facilitated significant new investment, with the Australian Pipelines and Gas Association (APGA) reporting that its members have built over $2.2 billion of new infrastructure providing 4000km of coverage across a large number of new gas transmission pipelines since 2000.[12] Work previously undertaken for the AEMC highlighted general acceptance that these arrangements have delivered timely and efficient investment.[13]

However, the significant increases in demand and the volatility of flows likely to be experienced on the transmission network in the future will test the flexibility of the current arrangements. As an example, the outage of a single LNG facility could lead to the redirection of gas equivalent to a significant proportion of total domestic demand. There are concerns that, under such circumstances, difficulties in reallocating rights to use pipelines will impede the ability of the market to reach an efficient outcome.

Consequently, a key focus of the reviews is to consider the extent to which changes to the gas transportation arrangements are required to enhance the efficiency of investment over the long-term in Victoria and to increase the flexibility of the arrangements elsewhere to promote the efficient usage of the system in the short-term.

1.1.2 The purpose and effectiveness of facilitated markets

As highlighted in the terms of reference, the facilitated markets in eastern Australia (the DWGM, the Short Term Trading Market (STTM) hubs and the Wallumbilla Gas Supply Hub) are not intended 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.[14]

However, it is not clear that the mandatory nature of the DWGM and the STTM is consistent with this objective. The requirement for all gas in these markets to be traded

11 See, for instance: Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, pp. 40-41.

12 APGA, Discussion Paper submission, p. 4.

13 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 121.

14 COAG Energy Council, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Terms of Reference, 20 February 2015, p. 2.

through them, despite the vast majority of transactions occurring through bilateral contracts outside of the markets, imposes additional direct and indirect costs on shippers. Participants are required to pay market fees on all gas flowed, irrespective of whether this is traded through the market to another party or not. The markets can also expose participants to a number of price risks, for instance as a result of deviating from their scheduled positions, some of which may be difficult or impossible to manage.

A drawback of the prevalence of bilateral contracting for gas is that little price information is publicly available. This lack of transparency can impede the price discovery process.[15] This is currently a particular concern to users as the market transitions to prices driven by the ability to export gas, and consequently influenced by international LNG prices.

Another key focus of the reviews will therefore be to consider whether and how additional information might be provided to resolve these issues. While bilateral contracting is likely to remain the main mechanism for trading gas, the increasing maturity of the market, combined with more dynamic and volatile market conditions, are likely to drive a move towards an increasing amount of shorter term contracts.

Consequently, the introduction and development of reference prices that broadly reflect underlying supply and demand conditions would be of particular value in assisting market participants and users in commercial decision making. Similarly, simplification of the market designs and developing the conditions for hedging products could act to assist participants in managing risk.

Therefore, as detailed in the following sections, consideration of how the price discovery process might be enhanced to enable more informed and efficient decision making, and how market designs might better allow for participants to manage risk, in addition to examination of transportation arrangements, are specified in the terms of reference as the main areas of focus for the reviews.

1.2 The East Coast Gas Market and Pipeline Frameworks Review

As noted above, the East Coast Review is to consider the design, function and roles of facilitated gas markets and gas transportation arrangements in eastern Australia. The AEMC has been asked to develop specific actions that can be implemented to strengthen the structure and competitiveness of the eastern Australian market and make recommendations for immediate implementation, where possible.[16]

The terms of reference are provided in full at Appendix A, but broadly require the Commission to consider:

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15 Transparent pricing can support informed and efficient decisions about gas allocation, whereas decisions made on incomplete information can lead to inefficient trade, price divergence and inefficient resource allocation. Nevertheless, caution should be exercised when considering the disclosure of price information, as this can result in unintended consequences such as tacit price collusion. (See Chapter 8 for a more detailed discussion).

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

- the appropriate structure, type and number of facilitated markets on the east coast, including options to enhance transparency and price discovery, and reduce barriers to entry;

- opportunities to improve effective risk management, including through liquid and competitive wholesale spot and forward markets which provide tools to price and hedge risk; and

- changes to strengthen signals and incentives for efficient access to, use of, and investment in, pipeline capacity.

The East Coast Review has been structured over two stages:

- Stage 1 outlines the overall direction for the east coast market development, including a factbase of current market outcomes and a gap analysis between the COAG Energy Council's vision for Australia's future gas market (see Chapter 2) and the existing arrangements, as well as setting out a number of recommendations that can be progressed immediately; and

- Stage 2 will more fully develop any necessary medium and long-term adjustments required to implement the vision, including the transition path required.

1.3 The Review of the Victorian Declared Wholesale Gas Market

In light of the significant structural changes underway across east coast gas markets, the Victorian Government, with the agreement of the COAG Energy Council, has asked the AEMC to examine the DWGM specifically to assess whether reforms are required to enhance the liquidity, transparency and flexibility of the current arrangements.[17]

The full terms of reference for the DWGM Review are provided at Appendix B. In summary, the Commission is required to consider:

- the ability of market participants to manage price and volume risk in the DWGM and options to increase the effectiveness of risk management activities;

- whether market signals and incentives are providing for efficient use of and investment in pipeline capacity in the Declared Transmission System (DTS) which underpins the DWGM;

- trading between the DWGM and interconnected pipelines; and

- whether the DWGM arrangements continue to facilitate market entry and promote competition in upstream and downstream markets and how this could be improved.

17 Department of Economic Development, Jobs, Transport & Resources (Victorian Government), *Review of the Victorian Declared Wholesale Gas Market*, Terms of Reference, 4 March 2015, p. 1.

In providing the terms of reference, the Victorian Government noted that there will be links between the recommendations and findings of the two reviews. Given these linkages the AEMC and the Victorian Government have agreed to combine the initial phase of the DWGM review with Stage 1 of the East Coast Review. As such, this report covers both reviews and includes the Commission's consideration of the issues arising in Victoria.

However, we are of the view that it is appropriate to consider options to address the issues identified in Stage 1 through discrete papers relevant to each review in the second half of 2015. This will allow for a greater focus on the specific circumstances of the current markets. As such, we intend to release a paper for consultation in August/September 2015, to further investigate the key areas of concern in the DWGM and clearly define the issues, as well as setting out some high level options for consideration. The timing of the two reviews is discussed in the next section.

1.4 Review process

1.4.1 Public forum and discussion paper

On 25 February 2015, the AEMC held a Public Forum to launch the East Coast Review. The forum provided an early opportunity for participants to discuss their views on the issues to be considered in the review, including those raised in the AEMC's brief discussion paper (released in advance of the forum to stimulate discussion).

The forum was attended by more than 70 representatives of gas pipeline owners, retailers, producers, large consumers, consumer groups, market regulatory bodies, other market participants and other experts covering a range of topics being considered in the review.

Following the forum, interested stakeholders were invited to make written submissions to the AEMC on issues raised in the discussion paper and at the forum. A comprehensive summary of submissions is provided in Appendix H. The presentations given at the forum, the discussion paper and submissions made to it are all available to download from the AEMC website.[18]

1.4.2 Stage 1 Draft Report

On 7 May 2015, the AEMC released the Stage 1 Draft Report for consultation. The Commission received 26 submissions on the draft report and we have drawn on these submissions in our analysis and throughout the Final Report.

A summary of submissions made to the Stage 1 Draft Report is also included as part of Appendix H. These submissions are also available to download from the AEMC website.

18 www.aemc.gov.au

1.4.3 Stage 1 Final Report and Stage 2

This is the final report for Stage 1 of the East Coast Review and reflects the initial phase of the DWGM Review. The report has been provided to the Council for consideration at its meeting in late July 2015.

Further stakeholder consultation will commence on Stage 2 of the review in August 2015, as shown in the table below.

Table 1.1 Indicative timing of the East Coast review and DWGM review

Due Date	Milestone	
	East Coast Review	**DWGM Review**
July 2015	**Stage 1: Final Report submitted to Energy Council and published**	
August/September 2015	East Coast Review Stage 2: • Wholesale Markets Discussion Paper; • establish wholesale markets working group; • establish Bulletin Board working group; and • further analysis and consultation on capacity trading	DWGM consultation paper: • energy market design issues; • network investment/capacity rights; and • inter-regional trade.
December 2015	Stage 2: Draft report for consultation, including request for COAG response on any significant adjustments or longer term initiatives identified	Draft report for consultation, including request for Victorian Government response on any significant adjustments or longer term initiatives identified
Following response from COAG Energy Council and Victorian Government	Stage 2: Final report	DWGM Final report

1.4.4 Advisory group

As required by the terms of reference, the AEMC has established an Advisory Group that will operate across both reviews.

The Advisory Group provides strategic advice and expertise to the Commission over the course of the review. The group meets periodically and is chaired by John Pierce, AEMC Chair. Advisory Group member organisations are listed in Table 1.2 below.

The Commission gratefully acknowledges the ongoing contribution made by the members of the Advisory Group.

Table 1.2 Advisory Group Members

Member	Role
Australian Energy Market Operator	Market operator
APA	Pipeline owner
Jemena	Pipeline owner and distributor
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)

1.5 Recent reviews into the east coast gas market and transportation arrangements

The current reviews follow a number of recent reviews and studies relating to the eastern Australian gas market. One of the aims of Stage 1 of the East Coast Review is to draw together the findings of this previous work.

Consistent themes have emerged across the reviews and are explored further in Chapters 4 to 8 of this report. Notably, most papers identified the need for a further strategic review into east coast gas market arrangements.

Appendix C summarises recommendations from the Scoping Study, the Eastern Australian Domestic Gas Market Study and the Gas Market Taskforce and the subsequent action taken to implement those recommendations. Many of the recommendations have been considered in this report, and will be further assessed in Stage 2 of the review.

1.5.1 The Scoping Study

The AEMC initiated the gas market scoping study in May 2013, in response to changes underway in Australia's eastern gas markets due to the emerging LNG export industry, and feedback from stakeholders through the strategic priorities review.[19]

The purpose of the Scoping Study was to:

- provide an overview of the changes underway in the eastern Australian gas market; and
- identify areas of potential improvement in the market and regulatory arrangements that may benefit from future market development work, prioritise their importance and identify who may be best placed to take the work forward.

The Scoping Study made 11 recommendations to improve the regulatory and market arrangements in the eastern Australian gas market. The highest priority identified by the Scoping Study was the need for a strategic review that would consider both:

- the direction that the eastern Australian gas markets should take over the next 10-15 years to transition to a more mature, well-functioning market; and
- the principles that should guide the development and design of facilitated gas markets in the future.

The Scoping Study also recommended a detailed review of the Short Term Trading Market (STTM) design and some elements of the Victorian Declared Wholesale Gas Market (DWGM) to determine whether improvements could be made that would better promote the NGO as a high priority.

1.5.2 Eastern Australian Domestic Gas Market Study

The Eastern Australian Domestic Gas Market Study was jointly prepared by the Australian Department of Industry and the Bureau of Resource and Energy Economics (BREE).[20] The Study examined the components of the eastern gas markets: supply and demand, infrastructure, and the nature and role of trading mechanisms. The Study identified a range of policy options for reforming the eastern gas market, including:

- establish a forward gas market reform agenda;
- improve the commercial and regulatory environment for infrastructure; and

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

- improve market data and transparency.

Within these policy options, the Study suggested that the Energy Council should consider commissioning reviews covering wholesale gas market competition and the suitability of the pipeline carriage models.[21]

1.5.3 Gas Market Taskforce

The previous Victorian Government established the Victorian Gas Market Taskforce, which was chaired by the Hon. Peter Reith. The Taskforce was asked to provide policy options for "improving the operation and efficiency of the eastern Australian gas market, including ways to facilitate market transparency and transmission capability, and increasing gas supply to meet increasing demand at competitive prices".[22] The Taskforce's report was released in October 2013.

The Taskforce made 19 wide ranging recommendations related to the production, transportation and retail segments of the supply chain. The Taskforce also made recommendations for improvements to the wholesale markets and transmission pipelines. In particular, the Taskforce recommended that the Victorian Government request the AEMC to undertake a thorough review of the pipeline capacity, investment, planning and risk management mechanisms in the DWGM, with the objective of ensuring arrangements for access to the pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.[23]

1.5.4 ACCC inquiry

On 8 April 2015, the Australian Government directed the Australian Competition and Consumer Commission (ACCC) to commence an inquiry into wholesale gas prices in eastern and southern Australia. Under the terms of reference, matters to be taken into consideration in the inquiry include:[24]

- 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;

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20 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014.

21 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 90.

22 Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, p. 9.

23 Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, p. 8.

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

- 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 published an issues paper for the review on 4 June 2015. The inquiry is to be completed by April 2016.

The ACCC inquiry and AEMC reviews are complementary, with the ACCC having much broader information gathering powers. We are working closely with the ACCC to ensure that the two processes are co-ordinated, and to understand the extent to which the ACCC's findings on the above issues can help to inform our considerations regarding market development.

1.5.5 Other reviews and input

The Productivity Commission recently released its research report *Examining Barriers to More Efficient Gas Markets*.[25] The report considers issues relating to exploration, production and transmission sectors. To assist with its analysis, the Productivity Commission developed a partial equilibrium model of the eastern Australian gas market.

On 30 March 2015, the Commission received a rule change request from the Energy Council to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board.[26] This is discussed further in Chapter 8.

We have also had regard to other recent reviews of the gas market prepared by the Energy Supply Association of Australia (ESAA), the Grattan Institute, Ai Group and St Vincent de Paul (Victoria).[27]

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25 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015.

26 Available from the COAG Energy Council's website: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/gtpct/

27 Energy Supply Association of Australia, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, Final Report, May 2013; Grattan Institute, *Getting Gas Right: Australia's Energy Challenge*, June 2013; Ai Group, *Gas Market Transformations: Economic Consequences for the Manufacturing Sector*, July 2014; Alviss Consulting & Darach Energy Consulting Services, *Gas Wholesale Markets and Retail Competition in NSW and Victoria*, July 2012.

1.6 Structure of this report

The next two chapters of this report are structured such that:

- Chapter 2 sets out the framework we intend to use to assess the effectiveness of existing market and regulatory arrangements, as well as any potential developments or enhancements; and
- Chapter 3 provides a summary of the key themes, findings and recommendations.

The remaining chapters then present our analysis and findings as follows:

- Chapter 4: Transmission Pipeline Frameworks;
- Chapter 5: the Short Term Trading Market;
- Chapter 6: the Declared Wholesale Gas Market;
- Chapter 7: the Gas Supply Hub; and
- Chapter 8: Information Provision (including the Bulletin Board).

Finally, the report also contains a number of appendices, as follows:

- Appendix A: East Coast Review Terms of Reference;
- Appendix B: DWGM Review Terms of Reference;
- Appendix C: findings from previous reviews;
- Appendix D: regulatory framework for transmission pipelines;
- Appendix E: STTM operation;
- Appendix F: DWGM operation
- Appendix G: GSH operation; and
- Appendix H: summary of stakeholder submissions.

2 Assessment Framework

The purpose of this chapter 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.

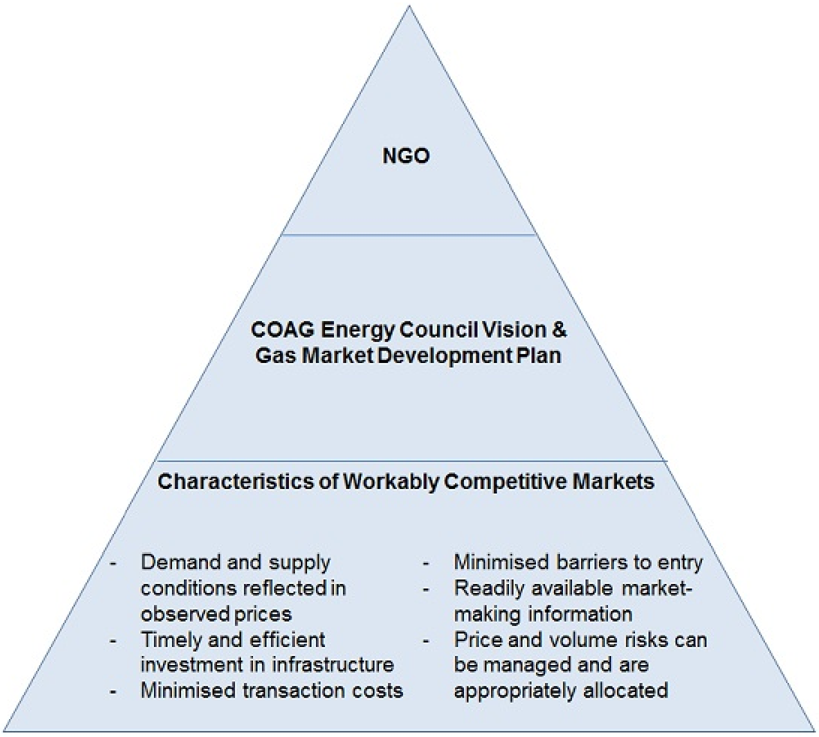
The assessment framework integrates the factors set out in both terms of reference that the AEMC must have regard to and articulates the relationship between them. High level principles that guide our market development and rule making work are also outlined, along with attributes that we consider are associated with a well-functioning, workably competitive gas market.

2.1 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.

Figure 2.1 Assessment framework



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 2.1, and each is discussed below.

2.2 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:[28]

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;

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

- 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;
- 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.

2.3 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:[29]

> "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:[30]

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

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

30 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/

factual information relating to resources projects, and rigorous science to ensure that communities concerns are addressed.

2. **Enhancing transparency and price discovery**:

   (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.

2.4 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.[31] These are:[32]

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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31 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."

32 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.

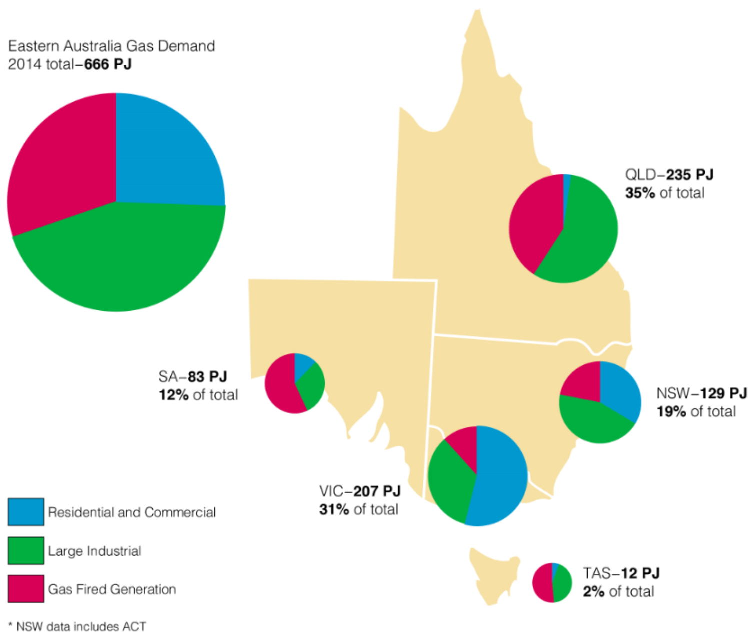
3 Summary of findings and recommendations

3.1 The east coast gas market is in the midst of change

Historically, natural gas has been used for a range of industrial, commercial and domestic applications in eastern Australia. It is used for residential heating and cooking, as an input for electricity generation and to support a wide range of industrial and commercial processes to manufacture pulp and paper, metals, chemicals, stone, clay, glass and certain foods.

As shown in Figure 3.1 below, large industrial use makes up the largest share of total gas demand in eastern Australia overall, accounting for 44 per cent of demand in 2014. Gas-fired generation is responsible for approximately one-third of demand, most of which is base load generation in Queensland and South Australia. Residential and commercial demand makes up a relatively small amount of demand in all states besides Victoria (and to a lesser extent, New South Wales), where it comprises over half of total demand.

Figure 3.1 Breakdown of domestic consumption of gas in eastern Australia, 2014



Source: AEMO, *National Gas Forecasting Report*, 2014. Note: These figures exclude LNG consumption in Queensland for 2014 which is estimated at 13.3 PJ. Totals may not sum to 100% due to rounding.

The gas market in eastern Australia is currently undergoing a significant transformation, and this is likely to have major implications on interactions between market participants and how transactions occur.

In an emerging market, with a handful of suppliers and customers, remote production facilities and pipelines had little alternative use if a buyer was to terminate its agreement to purchase the output of those assets. Long-term contracts were therefore implemented to reduce the risks and costs for both sellers and buyers of gas. In a small, stable market where transactions occurred infrequently, finding counterparties and undertaking negotiations was relatively straightforward.

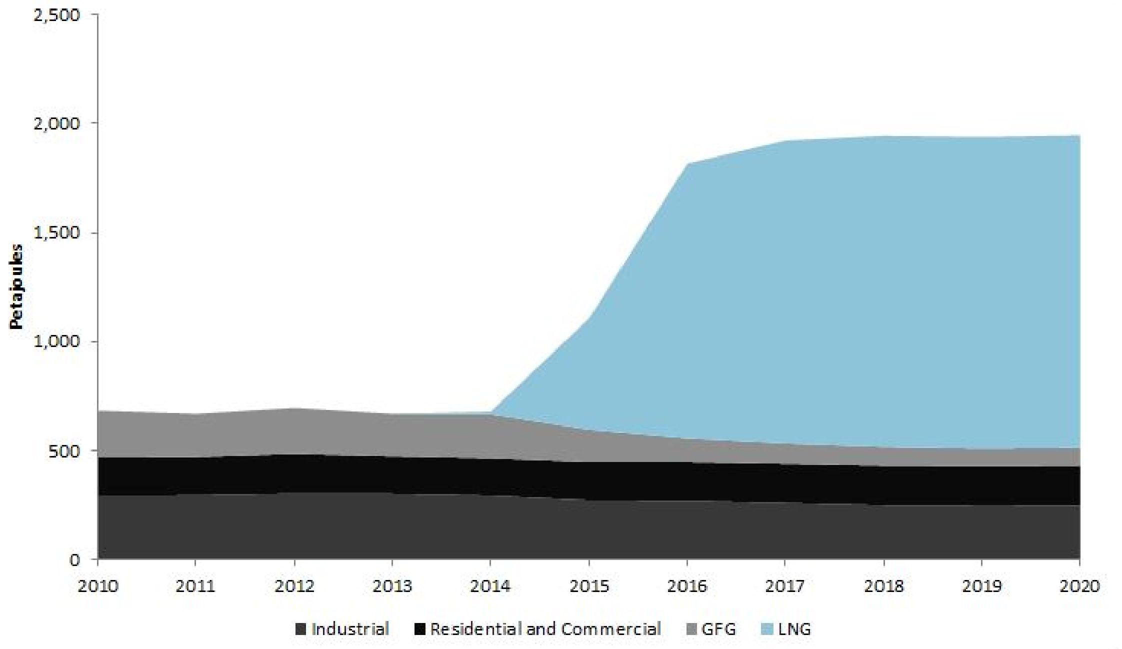
However, the development of the LNG industry, combined with the growing maturity of the east coast market, is expected to fundamentally alter these market dynamics. While bilateral contracts are likely to remain a fixture of the east coast markets in the future, industry participants are also likely to require more flexible and sophisticated mechanisms to manage their gas portfolios. These might, for instance, allow generators to purchase gas in the short-term to generate on a more "opportunistic" basis.

This chapter sets out the drivers of change in this market, the journey of market development to date and the case for continued development of the market into the future. The chapter also outlines the AEMC's Stage 1 findings and recommendations and sets the direction for Stage 2 of this East Coast Review and the DWGM Review.

3.1.1 LNG is creating opportunities for more short term trading of gas

In January 2015, the first LNG cargos were exported from Gladstone, with significant volumes of coal seam gas (CSG) coming online to meet the new demand from LNG. First exports represent a historic moment and the market has now entered a transitional period to a new supply/demand balance. The demand for gas in eastern Australia will increase substantially as the three LNG export projects ramp up to full production, as can be seen in Figure 3.2.

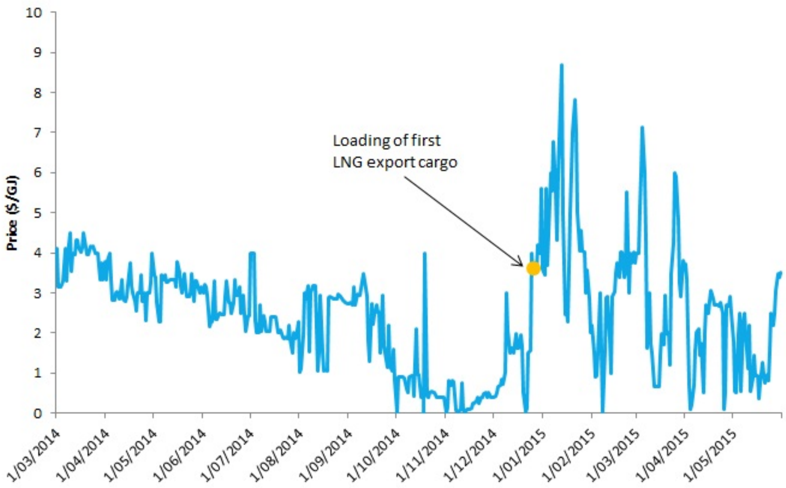
Figure 3.2 Demand for east coast gas is increasing to support LNG production



Source: AEMO, *National Gas Forecasting Report*, 2014.

Figure 3.3 shows the effect on ex ante prices at the Brisbane STTM hub of bringing the first LNG train online through 2014 and early 2015.[33]

Figure 3.3 Brisbane ex ante STTM prices have been volatile as first LNG cargos were shipped



Source: AEMC analysis; AEMO. Note: for ease of exposition, the data shown above exclude the ex ante price on 17 October 2014, which reached over $29/GJ.

The reduction in ex ante prices from the beginning of 2014 until late December reflected the need to bring 2,000 CSG wells progressively online to ensure sufficient gas was available to meet the requirements of the first LNG plant.[34] As the liquefaction of natural gas and loading of the first cargo took place, prices increased and exhibited greater volatility as excess gas in the market was used by the LNG plant.

Market conditions are expected to remain dynamic over the next 12 to 18 months as another five LNG trains are commissioned and ramped up to full production – potentially creating commercial opportunities for participants to engage in short term trading of gas as exporters seek to balance their cargo schedules.

Once the LNG trains are fully operational they will consume around 4,400 TJ of natural gas per day on average to meet their contractual obligations, and more if the trains are run at maximum capacity. This compares to average daily consumption on the east coast of around 1,665 TJ per day, and to winter peak demand on the east coast of 2,560 TJ per day.[35]

As can be seen in Figure 3.4, the gas required for LNG production is over double domestic consumption and storage injection on a daily basis. If one of the LNG trains

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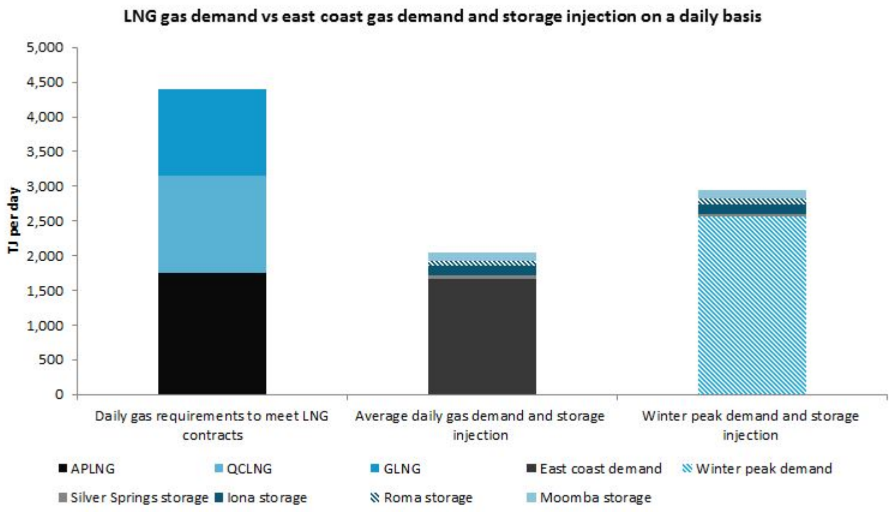
33 STTM ex ante prices are largely determined by participants' imbalance volumes, and are susceptible to both a small volume of trades and small number of market participants. As such the STTM price does not reflect a true commodity price.

34 BG Group 2014, Press release: BG Group loads first LNG cargo from QCLNG project in Australia, accessed 25 March 2015, <http://www.bg-group.com/~/tiles/?tiletype=pressrelease&id=744>

35 EnergyQuest, *EnergyQuarterly March 2015 Report*, pp. 69-75; AER Industry Statistics.

trips unexpectedly, and assuming an average turn down rate of 80 per cent for CSG wells, this would leave 125 to 174 TJ per day of gas to be absorbed by the domestic market, equivalent to six to 8.5 per cent of average daily gas demand and storage injection.

Figure 3.4 Daily gas demand from LNG is over double domestic market demand



Source: AEMC analysis; EnergyQuest; AGL; AEMO; Santos; AER.

The large amount of gas required for LNG exports compared to domestic consumption, combined with the inherent variability in supply from CSG, may stimulate the need for greater flexibility by participants to optimise their gas portfolios. A number of scenarios can be envisaged where the supply/demand balance in eastern Australia could shift quickly in response to LNG operations, including:

- during commissioning of the LNG trains;
- when the LNG trains shut down for maintenance;
- if an LNG train trips unexpectedly;
- if the capacity of the LNG export pipeline is reduced for unplanned maintenance; and/or
- if the productive capacity of the gas fields is reduced for unplanned maintenance.

Under each of these scenarios, flexibility to trade gas and pipeline capacity at short notice, as well as access gas storage, may be critical for the security of the gas system. This flexibility may also enable participants to maximise efficiency when balancing commercial gas portfolios and the market more broadly. An example of portfolio optimisation during commissioning of QCLNG Train 1 is discussed in Box 3.1.

Box 3.1 Commissioning of QCLNG Train 1

In the months leading up to the commissioning of QCLNG Train 1 and loading of the first cargo on 27 December 2014, prices at the Wallumbilla supply hub were as low as $0.20/GJ, with the volumes of trades ranging between 2,000 GJ and 40,000 GJ per day.[36]

Participants with flexible gas supply and pipeline capacity arrangements were able to take advantage of the short term price volatility that resulted. Origin Energy's activities over the second half of 2014 provide an insight into how gas portfolios can be optimised to take advantage of these commercial opportunities and support the efficient allocation of gas throughout the east coast market.

Origin was able to turn down production on its equity gas while purchasing 28 PJ of ramp gas.[37] This allowed the business to take advantage of the relatively cheap ramp gas to supply its customers, while preserving its equity gas for use at a later date. Origin was also able to monetise ramp gas through additional gas-fired generation and business sales.[38]

3.1.2 Gas prices are now linked to export markets

Unlike Western Australia and the Northern Territory, where LNG has been exported for a number of years, the east coast market has been insulated from international influences on domestic gas prices. Gas has historically competed against other fuel sources such as coal for use in electricity generation, with the abundance of low cost coal on the east coast effectively capping domestic gas prices.[39]

As the industry was developing it was common for bilateral gas supply agreements (GSAs) to be entered into for periods of 20 years or longer to underwrite the investments that producers, pipeline owners and users had to make in their assets.[40] Gas transportation agreements (GTAs) typically matched the terms of gas supply contracts. Most gas supply agreements contained take or pay clauses and prices were generally escalated annually in line with inflation, with provision for periodic reviews.[41]

In the past 15 years the outlook for the east coast gas market has changed considerably. Expected increases in gas-fired generation have not occurred due to the fall in

36 AER Industry Statistics.

37 Ramp gas is the increased production from CSG wells in advance of increased demand from the LNG trains.

38 Origin Energy, 2015 Half year results announcement, 19 February 2015, p. 21.

39 AER, *State of the Energy Market 2008*, p. 243.

40 For instance, the 540 PJ gas supply agreement between AGL and QGC for 20 years in 2006 and a 12 year agreement between Santos and TRUenergy for 425 PJ of gas announced in 2002.

41 NERA, *The Gas Supply Chain in Eastern Australia*, A report to the Australian Energy Market Commission, March 2008, p. 27.

electricity consumption and the removal of the carbon price, while six LNG trains with a combined capacity of over 1,500 PJ per annum will soon commence operations.[42]

LNG exports from the east coast are putting upward pressure on domestic gas prices due to the substantial increase in demand for gas. As the LNG projects represent such a large component of east coast gas demand, and the export contracts are linked to an international oil price, there has been a growing trend to link domestic gas contracts to oil.[43] The linkage of GSAs to international oil prices is a relatively new phenomenon for the domestic market and presents an unfamiliar risk for gas consumers to manage.

In recent times there have been concerns amongst some retailers and large industrial stakeholders that access to GSAs is becoming more difficult and more expensive as a result of this linkage. While some users have reported that they are unable to get responses to tenders for gas supplies extending beyond the next couple of years,[44] others have expressed a view that the inability to secure contracts is not linked to a shortage of gas, but a shortage of gas available at "legacy prices".[45]

As noted by the Productivity Commission recently:[46]

> "Reluctance to enter into supply commitments with gas users may be commercially rational behaviour in a highly uncertain market environment. Producers may be unable to charge prices in the eastern market that are high enough to compensate them for forgone export revenues and other costs of not fulfilling their export contracts... "

This period of volatility in the market coincides with the expiry of many domestic long-term GSAs,[47] raising questions around the market's resilience to such significant changes. The uncertainty appears to be triggering moves to shorter-term contracts and is likely to drive new approaches to risk management (for instance, to manage oil price and exchange rate fluctuations). The need for such levels of flexibility was largely unforeseen at the time that the current market frameworks were developed.

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42 MDQ Consulting, *NSW Wholesale Gas Market Report*, February 2014, p. 37.

43 Since 2013, a number of ASX-listed entities, including Origin Energy, Lumo Energy and AGL, have announced domestic gas contracts linked to oil.

44 Alliance of Industry Associations, Discussion Paper submission, 2015, p. 6. (Alliance members include Ai Group, Energy Users Association of Australia, Australian Aluminium Council, Australian Food and Grocery Council, Australian Steel Institute, Plastics and Chemicals Industries Association.)

45 Macquarie Research, *Australian East Coast Gas: a more orderly transition*, April 2015, p. 20.

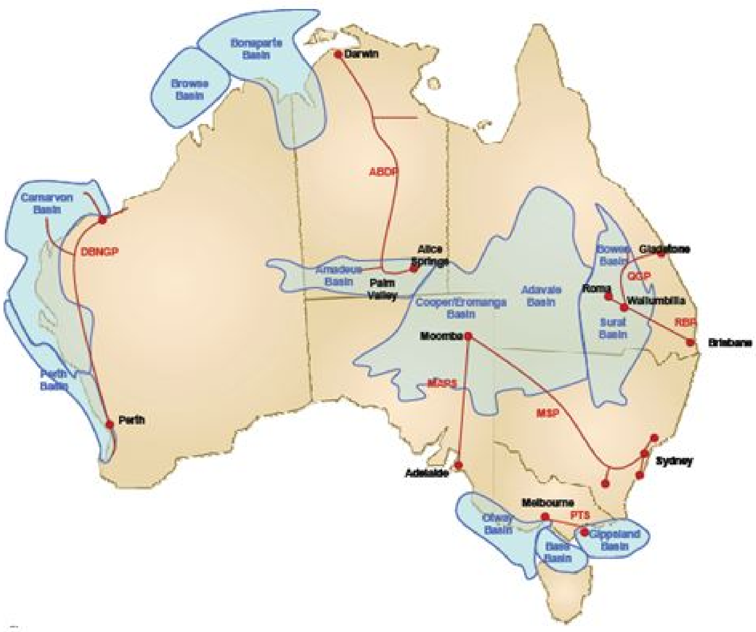
46 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 23.

47 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p.12.

3.1.3 East coast gas market frameworks were developed for different market conditions

During the early years of the development of the natural gas industry in Australia, gas flowed from production sources directly to demand centres. On the east coast, production around Roma was used to supply Brisbane and Gladstone; production at Moomba supplied Adelaide and Sydney; and Victorian offshore gas fields supplied Melbourne. There was effectively no integration between the sources of supply and demand, as can be seen in Figure 3.5.

Figure 3.5 Australian gas supply and pipelines in 1990



Source: NERA Consulting, *Gas Pipeline Regulatory Framework*, A report for the AEMC, September 2008, p. 5.

It was against this background that COAG agreed to implement a number of recommendations made by the Industry Commission and the Independent Committee of Inquiry (Hilmer Review). These recommendations included that legislative and regulatory barriers to inter and intra-jurisdictional trade of gas be removed and that a new national framework for third party access to gas transmission pipelines be introduced. Based largely on the national access regime in Part IIIA of the *Trade Practices Act 1974* (TPA),[48] the Gas Pipeline Access Law and Gas Code were introduced in 1997.

A key element of the Code was the concept of a coverage test that could be applied to each individual pipeline to determine whether or not it should be covered by the access regime.

Where a pipeline was covered, requirements that have come to be known as "full regulation" were applied. Under these arrangements, the relevant pipeline operator

48 Now the *Competition and Consumer Act 2010* (CCA).

was required to prepare an access arrangement and have the proposed price and non-price terms and conditions for reference service(s) approved by the relevant regulator. The pipeline operator and users were free to enter into a commercial agreement that differed from those set out in the access arrangement, but if a dispute about access arose a dispute resolution body was required to give effect to the access arrangement provisions.

The reference tariff therefore represents a benchmark for the negotiations through which service providers enter into bilateral contracts with access seekers to allocate pipeline capacity, with this form of arrangement being known as "contract carriage".

The access regime was applied to transmission and distribution pipelines. Other facilities in the gas supply chain, such as storage and gas processing plants, were not included.

In 1999, the Victorian Government introduced the DWGM, a compulsory market allowing market participants to trade daily imbalances. The DWGM operates across the DTS, a covered pipeline system, which, at the time the DWGM was introduced, was isolated from other transmission pipelines. The market design chosen introduced a different form of carriage arrangement on the DTS – market carriage – where usage of the pipeline is determined by outcomes in the wholesale market.

A second phase of national reform of the gas market occurred between 2002 and 2008, following an independent review of the strategic direction for energy market reform that was chaired by Warwick R. Parer,[49] the Productivity Commission's 2003–04 review of the gas access regime[50] and the 2006 Expert Panel report on energy access pricing.[51]

These reforms established the current energy market governance arrangements, including the formation of the AEMC and AER and creation of the NGL and NGR. By consolidating the state-based regulatory regimes, these governance arrangements were designed to reduce regulatory burden and increase consistency with the electricity regulatory framework.[52] The new framework also introduced two further regulatory options into the gas access regime:

- "light regulation," which places greater emphasis on commercial negotiation and information disclosure than full regulation, but which retains provision for parties to have recourse to the dispute resolution mechanism if negotiations fail; and
- a 15 year coverage exemption for greenfield pipelines.

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49 Parer, Warwick R., *Towards a Truly National and Efficient Energy Market*, 20 December 2002.

50 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004.

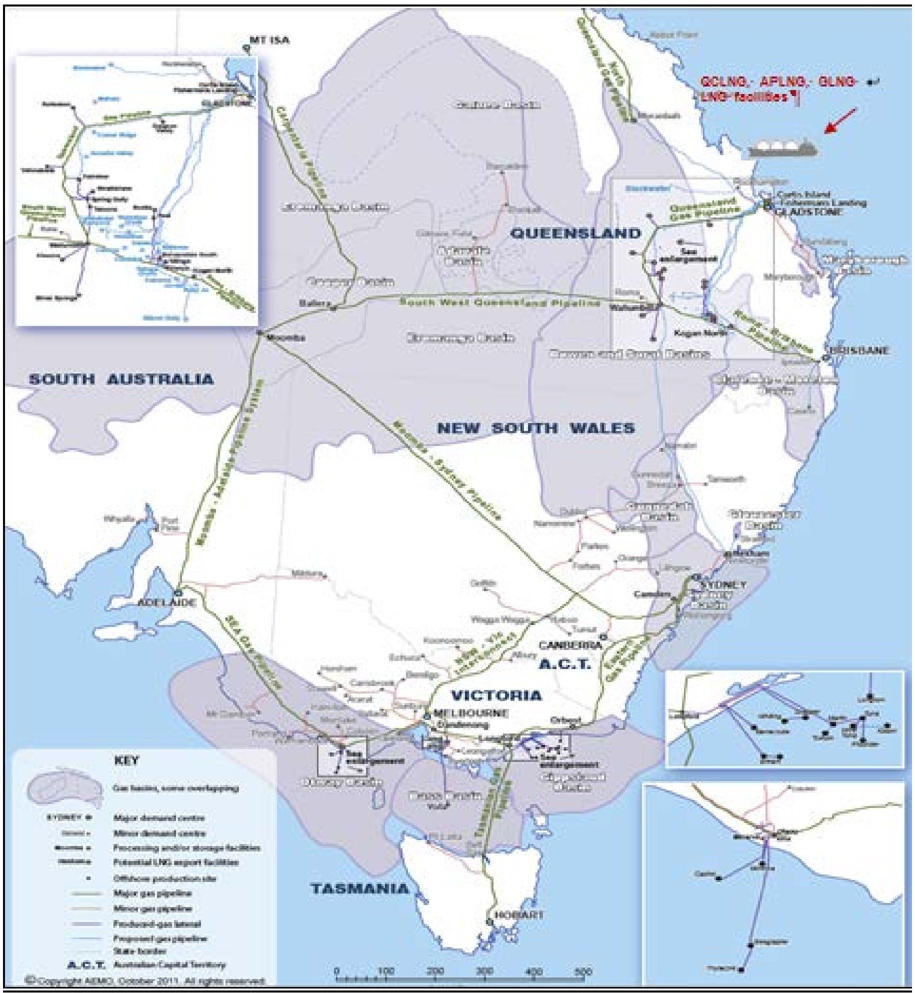
51 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

52 Parer, Warwick R., *Towards a Truly National and Efficient Energy Market*, 20 December 2002.

In 2005, the COAG Energy Council established the industry-led Gas Market Leaders Group (GMLG) to accelerate the development of the natural gas market. Following the GMLG's recommendations, the National Gas Services Bulletin Board (BB) and Gas Statement of Opportunities (GSOO) were implemented in 2008–09 to increase market transparency, while the STTM was introduced to provide a day-ahead market for trading gas between transmission and distribution pipelines and a balancing service. The STTM started at hubs in Adelaide and Sydney in September 2010, with a hub being established in Brisbane in December 2011.

In December 2012, the Energy Council asked AEMO to develop the Wallumbilla Gas Supply Hub (GSH), the objective of which was to enhance transparency and reliability of gas supply by creating a voluntary market to provide a low-cost, flexible method to buy and sell gas. Wallumbilla was chosen for its proximity to significant gas supply and demand centres, and is a transit point situated at the intersection of three major pipelines.[53]

Figure 3.6 East coast gas supply and pipelines in 2014



Source: AEMO, *Gas Statement of Opportunities*, 2012. Amended to reflect the location of LNG facilities.

53 These pipelines are the Roma to Brisbane Pipeline (RBP), the South West Queensland Pipeline (SWQP) and the Queensland Gas Pipeline (QGP).

Over the period since the start of the reform process, the gas market environment has changed significantly. Many new pipelines have been constructed, most recently the LNG pipelines in Queensland and, prior to that, the Eastern Gas Pipeline, the SEA Gas Pipeline and QSNLink, amongst others. As a result, the market in eastern and southern Australia is now fully integrated, with transmission pipelines beginning to form an interconnected grid, as can be seen in Figure 3.6

In comparison, and despite the ongoing reform and development process, the market and regulatory frameworks appear fragmented and disjointed. Today, on the east coast, there are:

- three different facilitated market designs (DWGM, STTM and GSH) with five pricing points;
- two different pipeline carriage arrangements (contract carriage and market carriage); and
- four principal sets of pipeline regulatory arrangements (full regulation, light regulation, no regulation and 15 year coverage exemptions).

It is no longer clear that the objective underpinning the initial development of the access regime – to provide access to individual gas pipelines – remains relevant in the context of an interconnected network and the changing market dynamics discussed earlier in this chapter.

Against this background the Commission has considered whether the current frameworks remain fit for purpose and whether there are barriers that impede gas from flowing to its highest value use.

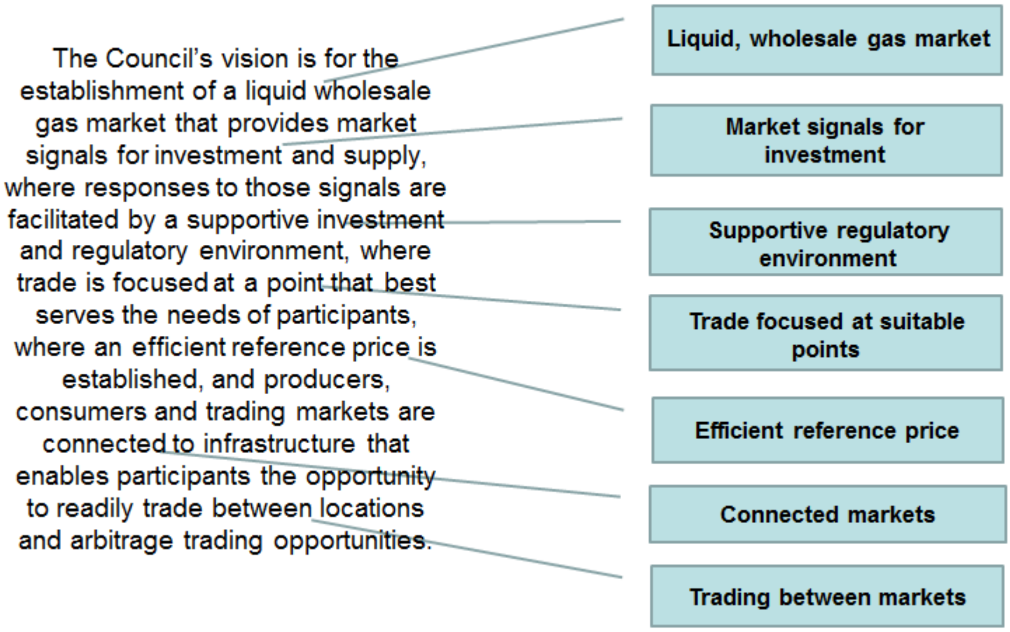
3.2 Assessment of existing market and pipeline frameworks

As discussed, the external environment within which the east coast market exists is shifting. There is likely to be a more dynamic supply and demand balance, patterns of gas flow will change and prices are likely to be more volatile and increasingly influenced by developments in international energy markets.

In recognition of this transformation, the Energy Council released its Vision for the Australian gas market in December 2014, and tasked the AEMC with undertaking this review in order to assist the Council in realising it.

The Vision can be broken down into seven elements, as shown in Figure 3.7 below.

Figure 3.7 Key elements of the COAG Vision



In accordance with our assessment framework, we intend to use the Vision as a guide to the high level direction that gas market development should take in order for the NGO be achieved. This section therefore considers the extent to which the current market and pipeline frameworks are aligned with each element of the Vision.

3.2.1 Liquid, wholesale gas market

As discussed earlier in this report, gas has historically been traded between market participants on a bilateral basis, and this remains the predominant means of exchange today.

In Victoria and at the STTM hubs (Adelaide, Brisbane and Sydney), all gas has to be transacted through the relevant facilitated market (the DWGM and STTM, respectively). However, in practice, the vast majority of trades – between 80 per cent in Victoria and 95 per cent in Brisbane[54] – occur between the same entities. These transactions are occurring solely because of the compulsory nature of the market and are not adding value in terms of bringing together buyers and sellers to trade.

Nevertheless, the DWGM and STTM play a number of important roles. They have provided a largely effective and competitive gas balancing service, which supports retail competition. A number of participants, including new entrant retailers, have found them to be a useful way of initially entering the gas market before committing to bilateral gas supply and transportation agreements. We have also heard from large

54 Further information is provided in Chapters 5 and 6 . Note that some stakeholders have suggested that these figures may, to some degree, understate the level of trade occurring in practice.

industrial users that the markets provide assistance in supplementing volumes secured through bilateral contracts.[55]

Although only operational for around a year, market participants are generally of the view that the Wallumbilla GSH provides a useful and low-cost platform for the commodity trading of gas. There have been between five and eight participants per month trading at the hub. However, volumes traded to date remain relatively small in the context of the wider market: the 3 PJ traded from market-start until the end of March 2015 represents approximately one per cent of total gas consumption in Queensland during 2014.[56]

It seems likely that the liquidity of the market at Wallumbilla is being impeded by physical limitations on flows, with trades split across three different locations (one for each of the three major pipelines at Wallumbilla). AEMO is currently undertaking work to consider how the three trading locations might be consolidated, with stakeholders generally being supportive of this process.[57]

3.2.2 Market signals for investment

In the last two decades, there has been significant investment undertaken in the gas market in eastern Australia. Production has increased markedly, with the recent investment in CSG production in Queensland and in the associated LNG export facilities currently having a transformative effect on the industry. There are concerns that rising prices are signalling the need for further supply and that this may not be occurring due to regulatory barriers. However, this issue is being considered by governments through processes outside of this review.[58]

In the pipeline sector, it is generally accepted that the contract carriage model has efficiently facilitated new investment. Bilateral contracting between users and pipeline developers has led to the construction of strategically important new pipelines, such as the Eastern Gas Pipeline, the SEAGas Pipeline and the QSNLink. Improvements are also being undertaken to allow for bi-directional flows on many major pipelines, such as the Moomba to Sydney Pipeline, the Moomba to Adelaide Pipeline System and the Roma to Brisbane Pipeline.[59] These developments will significantly enhance the ability of gas to flow to where it is most valued.

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55 Adelaide Brighton Cement Limited, Discussion Paper submission, p. 2; Qenos, Discussion Paper submission, p. 4.

56 Total gas consumption for Queensland in 2014 was estimated to be 266 PJ, see: EnergyQuest, *Energy Quarterly*, March 2015, Figure 44, p. 108.

57 APA, Discussion Paper submission, p. 18; Santos, Discussion Paper submission, p. 5; ESAA, Discussion Paper submission, p. 6; Origin Energy, Discussion Paper submission, p. 4; Lumo Energy, Discussion Paper submission, pp. 9-10.

58 The Australian Government's Domestic Gas Strategy, released on 14 April 2015, is intended to inform discussions with state governments, who have primary responsibility for onshore gas development, on ways to address unnecessary barriers to bringing on new gas supply.

59 AEMO, *Gas Statement of Opportunities*, April 2015, pp. 2-3.

However, the market contract carriage model in Victoria does not appear to be similarly supportive of market-led investment in the DTS. Any privately funded augmentation of a shared DTS asset would be available for use by all market participants, and this appears to have deterred such investments.[60]

APA has told us that the current market driven investment to expand the northbound export capacity of the DTS was only made possible by the certainty given by having contracts for firm capacity in place on the interconnected contract carriage pipeline.[61] In practice, investment in the DTS has largely relied on the regulatory process, whereby expenditure is approved by the AER and its recovery is shared across users.

3.2.3 Supportive regulatory environment

The gas regulatory framework is underpinned by the access regime, supplemented by rules governing the facilitated markets and Gas Bulletin Board. The access regime applies only to pipelines and not to storage or gas processing facilities, although these may be subject to requirements to report information.

Stakeholder submissions to date on the regulatory framework have expressed diverse views. A number of stakeholders consider that the framework is working as policy makers intended, with some suggesting that the coverage provisions have contributed to the ability of pipeline owners and users to work together to expand pipeline capacity and meet market demand.[62]

However, other stakeholders have claimed that there are some gaps in the current arrangements, most notably associated with investment in the market carriage model and secondary capacity trading under contract carriage, but also concerns with the effectiveness of the access regime in mitigating market power.[63]

In addition to the difficulties associated with market-led investment in Victoria, APA, the owner of the system, has expressed strong concerns about the effectiveness and timeliness of the regulatory process in determining investment on the DTS.[64] In contrast, others, including the AER, have questioned the view that the regulated model of transmission investment in the DTS is affecting efficiency in the level and timing of investment.[65]

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60 Gas Wholesale Consultative Forum, *Discussion Paper: GWCF 10-095-01 Investment AMDQ*, 5 August 2010.

61 APA, Discussion Paper submission, p. 14.

62 APGA, Discussion Paper submission, p. 41; APA, Discussion Paper submission, p. 3; Jemena, Discussion Paper submission, p. 1; Santos, Discussion Paper submission, p. 7.

63 APA, Discussion Paper submission, p. 12; APGA, Discussion Paper submission, p. 36; GDFSAE, Discussion Paper submission, p. 6; Orora, Stage 1 Draft Report submission, p. 2; AGL, Stage 1 Draft Report submission, p. 4; APLNG, Stage 1 Draft Report submission, p. 2; MEU, Stage 1 Draft Report submission, pp. 12-13.

64 APA, Discussion Paper submission, p. 12.

65 AER, Discussion Paper submission, pp. 3-4; Lumo Energy, Discussion Paper submission, pp. 12-13.

Outside of Victoria, the significant increases in demand and in the volatility of flows likely to be experienced on the pipeline network will test the flexibility of the current arrangements. While governments and industry have made progress in recent years, barriers remain to short-term and secondary trading of pipeline capacity.

Although questions have been raised in relation to the incentives on holders to release capacity if it would be more highly valued by another party, many of the barriers to capacity trading appear to relate to search and transaction costs. In particular, stakeholders have highlighted that, on a point-to-point pipeline with multiple injection and withdrawal points, defining capacity rights and system operation may be especially difficult.[66] This will naturally tend to inhibit the specification of fungible rights and liquid trading.

While continued industry-led initiatives are welcome, a question for Stage 2 of the review will be whether any regulatory intervention is necessary to better facilitate capacity trading. To the extent that this would require placing regulatory obligations on currently uncovered pipelines, it is unclear whether this could be supported by the existing regulatory framework.

Consequently, given the increasing interconnectedness of the pipeline network and the Energy Council's Vision to establish a liquid, competitive gas market, we are of the view that there would be value in considering whether the current regulatory framework is still fit for purpose and would be likely to support the efficient allocation and reallocation of pipeline capacity.

A further matter not contemplated under the current regulatory environment is the concept of Hub Services. As AEMO progresses its work plan to consider measures to increase liquidity at Wallumbilla, there is likely to be a need to consider the possible role of economic regulation of Hub Services and, if necessary, how this would be accommodated in the regulatory regime.

3.2.4 Trade focussed at suitable points

The selection of Wallumbilla as the location for the Gas Supply Hub reflected its strategic location at the intersection of three major pipelines, close to significant sources of gas production and relatively proximate to major demand centres at Brisbane and Gladstone. To the extent that it is possible to develop a liquid trading hub, Wallumbilla appears to be a suitable location.

The decision to introduce the STTM in Adelaide, Sydney and Brisbane was driven by their status as centres of demand, and the need for some form of balancing market in these locations appears clear.

However, it is less certain that developing any significant volume of commodity trading at the current STTM hubs is a realistic goal. It appears that such trade is more naturally undertaken at supply centres. In particular, the value of the Brisbane STTM

66 AGL, Discussion Paper submission, p. 6; EnergyAustralia, Discussion Paper submission, p. 3.

has been questioned given its relatively lower and more predictable load profile, and the presence of the Wallumbilla GSH in close proximity.[67]

As a major centre of supply, Victoria would appear to be a suitable point for trading. However, it is not clear that the current design of the DWGM best facilitates trading between producers and retailers/users. We understand that most trade continues to be undertaken through bilateral contracts at the major production facility. Consequently, while there appears to be a need to reconsider the design of the DWGM, this should be done in the context of providing a hub for commodity trading as well as a balancing market.

As part of the second stage of the review, we intend to develop a strategic approach to the location of trading points. In a relatively small market such as that in eastern Australia, there would appear to be a limit to the number of points at which it would be realistic to expect liquid trading to develop. Given that the market in Queensland will be significantly affected by the dynamics of the LNG export industry, and with there still being limited interconnection between Queensland and the south-east, there would appear to be a role for at least one more hub in addition to Wallumbilla. There may be an opportunity to redevelop the DWGM in this way, as mentioned above.

It is in this context that consideration needs to be given to the potential introduction of a GSH location at Moomba. Although we see some merit in this, given Moomba's status as a production centre linked to multiple pipelines, there is a need to consider how and when it might best fit into the wider east coast market. While a number of stakeholders have expressed support for Moomba, many have done so in the context of considering Moomba's likely role in the broader development of the market.[68]

3.2.5 Efficient reference price

Reference prices are important to help market participants and users form expectations about future price levels when entering bilateral contracts. Currently, neither the STTM nor the DWGM appear capable of providing a credible indicator of underlying demand and supply due to prices in these markets reflecting daily imbalances between participants’ requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to only a very small portion of total volumes transacted on the markets (~5 – 20 per cent)[69] meaning that the observed market price can be susceptible to both a small volume of trades and a small number of market participants.

Given its location at a centre of both supply and demand, the DWGM may have the potential to be used to form a reference price, and a number of derivative products

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67 APA, Discussion Paper submission, p. 10; Origin Energy, Discussion Paper submission, p. 4.

68 Santos, Stage 1 Draft Report submission, p. 5; APA, Stage 1 Draft Report submission, p. 17; AGL, Stage 1 Draft Report submission, p.4; GDFSAE, Stage 1 Draft Report submission, p. 6; ESAA, Stage 1 Draft Report submission, p. 5.

69 Note that suggestions have been made to the Commission that these statistics may underestimate the amount of trade occurring. See: CQ Partners, Stage 1 Draft Report submission, p. 3.

have been introduced by the Australian Stock Exchange (ASX) linked to the price payable at the beginning of the day in the DWGM. However, these products have not been heavily traded, which is likely to be because the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream producers using bilateral contracts, and then selling it to themselves through the DWGM.

In addition, the derivative products only provide a hedge against the beginning of day price, and the price in the DWGM can be reset a further four times over the course of the day. Participants are also liable for deviation payments and uplift charges.

As a pure commodity market, the Wallumbilla GSH may have the potential, as it matures, to provide a credible reference price that reflects underlying demand and supply conditions in Queensland. However, such an outcome may be dependent on resolving the current limitation whereby physical constraints within the hub split trading across three locations.

3.2.6 Connected markets

The significant investment made in new and augmented transmission pipelines over the last two decades has ensured that all major markets in eastern and southern Australia are today physically interconnected.

However, as outlined previously, it is not clear that, in practice, gas can always flow seamlessly between markets. Barriers, such as the detailed nature of transportation contracts and transaction costs, may be limiting the extent to which pipeline capacity can be reallocated to its most valuable use.

We also understand that differences in gas specification on pipelines used to supply the LNG export facilities (including the SWQP and QSN) may be increasingly likely to affect the efficient trade and movement of gas from southern sources into Queensland.[70] Given the ACCC is looking into this matter, we intend to work closely with it to consider further the extent to which it is an issue.

3.2.7 Trading between markets

Due to the confidential nature of gas supply and transportation agreements, it is difficult to assess the materiality of current trade across markets. The absence of credible reference prices for gas and lack of pricing information for uncovered pipelines makes it difficult to know whether gas is flowing to the highest value use.

However, the ability of users to access capacity contracted to others through trades has emerged as a major theme for the review. Although significant work has been carried out in this area by industry and governments, it appears that barriers remain and that liquid trading in secondary pipeline capacity has yet to materialise.

70 GDFSAE, Stage 1 Draft Report submission, p. 6.

The ability to trade between the DWGM and contract carriage pipelines outside of Victoria also appears to be an unresolved issue. While some stakeholders have noted that steps have been taken in the last two years to address issues associated with the interface between the two sets of arrangements,[71] views have also been expressed that problems remain, particularly those associated with curtailment.[72]

3.3 Areas of focus for the review

As highlighted by the preceding analysis, our work to date suggests that there are a number of gaps between the current frameworks and the Energy Council's Vision. Although our work going forward may not be limited to only these areas, the following three issues are those which will form the main areas of focus for the second phase of the reviews.

3.3.1 Liquid wholesale market delivering efficient reference price

Although there are three different types of facilitated market on the east coast, in five different locations, none yet deliver an efficient reference price. It is not clear that there is currently any strategic plan regarding the type and location for facilitated markets, and we consider that this is something that should be addressed.

We consider there are also questions regarding the objectives for, and design of, each type of market:

- **STTM**: It is not clear that the delivery of an efficient reference price is likely to be a realistic expectation of the STTM, given the difficulties of developing any significant volume of commodity trading at points so remote from production. Consequently, we consider there to be questions as to what the objectives for the STTM should be and whether the market design can be simplified while still meeting given objectives.

- **DWGM**: It will be important to fully understand why more trading between participants is not occurring in the DWGM, and whether it would be possible to establish a more meaningful reference price. One issue appears to be the market design, where intra-day revisions to the market price and the existence of a number of ancillary charges prevent the identification of a "clean" price to form the basis of derivatives trading.

- **GSH**: The GSH at Wallumbilla appears to represent a good model for a wholesale trading market. However, the market design is incomplete, in terms of its ability to address physical constraints within the hub. We note that resolving this issue may have significant implications for the wider regulatory frameworks, for instance, if there was a need for economic regulation of Hub Services.

71 APA, Discussion Paper submission, pp. 14-15; AGL, Discussion Paper submission, p. 5; Origin Energy, Discussion Paper submission, p. 3; APGA, Discussion Paper submission, p. 34.

72 APA, Discussion Paper submission, p. 15; Origin Energy, Discussion Paper submission, p. 3; Santos, Discussion Paper submission, p. 6.

Information

An important consideration in developing liquid and workably competitive markets is that participants have ready access to the information they require to make informed consumption, production, transportation and investment decisions.

Unlike some other markets, gas and gas transportation services in the eastern Australian gas market have historically been sold under confidential and highly customised medium to long-term contracts. The resulting lack of transparency means that the price discovery process can involve lengthy bilateral negotiations and may be afflicted by informational deficiencies and asymmetries.

Although some steps have been taken to try to reduce informational barriers, there are still some informational gaps, which are becoming more apparent as participants seek to adapt to the increasingly dynamic market environment. We therefore consider that there are important questions as to whether improvements can be made to the coverage, timeliness and accuracy of market and transportation information to assist the price discovery process and, over the longer term, enhance the liquidity of trading.

3.3.2 Ability to trade pipeline capacity in response to price signals

The increasingly interconnected nature of the gas transmission pipelines on the east coast and the impacts of the LNG export industry are two of the factors driving a much increased interest in trading pipeline capacity. Such trade is important to allow the market to reach efficient outcomes.

While most stakeholders raising this issue have referred to situations in which prospective users seek access to contracted but unutilised capacity, it is also important that trades can be facilitated in situations where capacity being used can be traded to another party if they value it more highly.

Given that pipeline operators offer as-available capacity and shippers would appear to have an incentive to offer unused capacity (or capacity which is not highly-valued), we are interested in gaining a better understanding of why more of a market has not developed.

A number of stakeholders have highlighted an apparent tension between demand for increasingly bespoke and tailored gas transportation contracts reflecting the more complex market environment on the one hand, and a need for more standardised contracts in order to allow for capacity trading on the other. Fully understanding this issue is therefore likely to require assessing a number of factors including contractual provisions, the incentives acting on a range of parties, the practicalities and costs associated with trading capacity, and processes for using pipelines.

3.3.3 Pipeline investment in the DTS

The nature of the market carriage arrangements are such that shippers cannot obtain firm access rights for the transportation of gas and therefore have little incentive to underwrite investments in the pipeline system. However, it is not currently clear whether a mechanism to allocate firm rights to shippers in response to them funding network augmentation could be accommodated within the current DWGM market framework or whether this would require significant redesign of the market.

In the absence of market-led investment, most capacity expansions have been progressed through the regulatory process. However, with the major driver on network expansion being a requirement to enhance the ability to ship gas across the system for "export" to other jurisdictions, it is questionable whether it is appropriate for the risks associated with over-investment to be borne by Victorian consumers. Inconsistent views have also been expressed as to the effectiveness and timeliness of the regulatory process, which we will investigate further over the next stage of the review.

3.4 Directions and recommendations

The issues identified above as the major areas of focus for the reviews are complex and long-standing. As set out in section 3.1.1, the market and regulatory frameworks have evolved in a somewhat piecemeal manner since the development of the initial gas access regime in the 1990s. Consequently, fully understanding the issues and then developing and assessing potential solutions requires detailed analysis and consultation with industry.

Stage 2 of the review is intended to allow for the development of any medium and long term adjustments necessary to implement the Energy Council's Vision. Many of the issues that we have identified in Stage 1 of the review fall into this category, with it being possible to address only relatively few issues through incremental changes that can be made immediately. This section sets out how we intend to progress these medium and longer term adjustments.

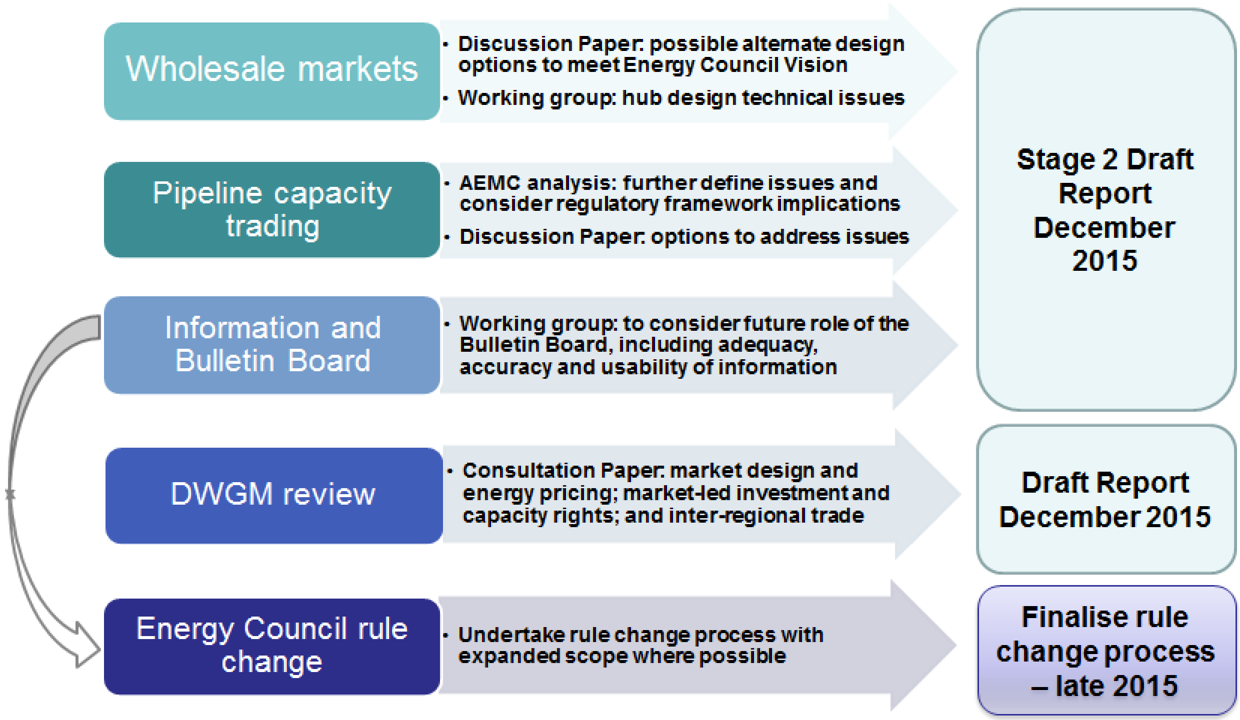
Nevertheless, we consider that there are some areas where more immediate progress can be made. This section therefore also discusses these matters and the recommendations we are making to address them.

3.4.1 Directions for Stage 2 and the treatment of medium to long term issues

In order to define the long term roadmap for market development we intend to progress the key issues identified above through four main workstreams, as shown below.[73]

73 Figure 3.8 also includes the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change proposed by the COAG Energy Council.

Figure 3.8 Stage 2 Workstreams



Wholesale markets

The Energy Council's Vision clearly outlines a desire for the development of an efficient reference price. Given their design and location, we consider it questionable whether delivery of efficient reference prices is likely to be a realistic expectation of the STTM hubs. The STTM is trying to achieve multiple objectives and, as a result, is relatively complex and costly. The main function played by the STTM is a balancing market, although a number of stakeholders, particularly large users, have also highlighted the value they derive from being able to use the STTM as a supplement to bilateral contracting for gas supplies.

Consequently, we intend to consider what the objectives of the STTM should be, and whether it would be possible to simplify the design while still meeting these objectives. This will be important in allowing us to develop a longer term plan for the development of the facilitated markets on the east coast.

To commence this work, we intend to publish a Discussion Paper for consultation in early August 2015 that will outline the characteristics of different gas market designs and potential structures that could be implemented to meet the Energy Council's Vision. A working group comprised of industry and user representatives will also be established to provide the Commission with expert technical advice as it finalises its recommended approach for the Stage 2 Draft Report in December 2015.

Through this process we will work closely with AEMO as it progresses its work to further develop the design of the Wallumbilla GSH. We will consider the interaction between the STTM and commodity trading at current and potential GSH locations, and will also consider broader questions, such as whether trade should be at specific physical locations or at "virtual" points encompassing parts or all of the pipeline network. We will investigate the scope for increasing the consistency in gas market designs across the east coast to minimise transaction costs, where possible. Finally, we will also consider implementation and transitional issues, such as whether there would be merit in trialling a simplified market design at Brisbane.

Pipeline capacity trading

Based on our Stage 1 analysis, the submissions we have received and observations from earlier reviews, it appears that there are some aspects of the pipeline arrangements used outside of Victoria that impede the efficiency with which capacity rights are reallocated and used.

These issues are complex and will require more detailed analysis than has been possible to achieve in Stage 1 of the review. A major element of our Stage 2 work will therefore be to investigate and consider potential measures to better facilitate pipeline capacity trading.

We intend to initially undertake further work to define the issues or barriers to trading, before developing and assessing options to address these. In particular, we intend to examine and potentially draw on approaches to this issue used in international markets in Europe and North America (to the extent that they might be applicable to Australian circumstances). To this end, we have commissioned Market Reform to undertake a study of International Gas Markets, which has been published alongside this report.

As part of this more detailed work, we will consider whether the existing regulatory framework is likely to remain fit for purpose given the changes underway in the market and whether changes to this framework (including the third party access regime) would be required to improve the efficiency with which pipeline capacity is allocated and reallocated.

Information provision and the Bulletin Board

In our work to date, it has become clear that informational sources on the eastern Australian gas market are fragmented and somewhat under-developed by international standards. Consequently, in Stage 2 of the review, we intend to consider the strategic direction for information provision, particularly the development of the Bulletin Board.

To progress this, we propose to form a Bulletin Board technical working group, which will be comprised of representatives from industry, governments and market bodies. The group will consider potential further development of the Bulletin Board, but will also re-examine the structure underpinning it, for instance which pipelines are included and its ability to accommodate bidirectional pipelines.

We will develop a structured workplan for the working group that will cover issues such as: Bulletin Board coverage and registration; the presentation and usability of data; the timeliness and reliability of information; enforcement and compliance; and governance. Our preliminary thoughts on the changes that could be made to the Bulletin Board to increase its scope and improve its usability and functionality are outlined in Table 3.1. The group will therefore also consider whether the benefits of such improvements would be likely to exceed the costs, and will provide its assessment back to the AEMC to be considered as part of our Stage 2 work.

Table 3.1 Preliminary suggestions for improvements to the Bulletin Board

Improvement	Detail
Include information on prices from the facilitated markets	Develop a new facilitated markets pricing page that includes: • current and historic information on prices and other relevant information from the GSH, STTMs and DWGM; and • the AER's Weekly Gas Market Report.
Include planning and longer term forecast information	Develop a new long-term forecast and planning page that includes the GSOO, the National Gas Forecasting Report and associated material.
Expand the scope of capacity listing	Expand the scope of the capacity listing page to include a separate listing service for gas, transportation and storage capacity.
	Consider, in consultation with APA and Jemena, the extent to which bids and offers on their respective capacity trading sites could also be published on the Bulletin Board so that prospective shippers can find this information on a single website
	Reconsider whether market participants should be required by the BB procedures to list available gas or spare capacity through the GSH, given the financial and logistical hurdles this may present.
Allow transportation and storage charges to be published	Reconsider whether market participants should be required to list available gas or spare capacity through the GSH, given the financial and logistical hurdles this may present.
Further improvements to the BB's layout and functionality	Continue to improve the usability and functionality of the Bulletin Board by, for example: • making key information easier to find on the home page; • developing separate pages for production, transmission and storage, which would include the information Bulletin Board facilities are required to provide AEMO; • providing greater clarity about what some of the data represents; • making greater use of some of the information provided by Bulletin Board facilities and improving the website's charting capability[74]; and • establishing a new section for the BB procedures and the AER's compliance reports.

74 For example, the actual flow data charting capability could include information on standing capacities as well as actual flows.

A particular area of focus for Stage 2 of the review will be on compliance and enforcement. If the Bulletin Board is to become a reliable repository of market making information, participants will need to have greater confidence in the accuracy and timeliness of the information that BB facilities are providing that they currently do. Consequently, we intend to work closely with AEMO and the AER to consider how it might be possible to streamline the process for monitoring and enforcing compliance, to identify and address areas of systemic non-compliance in a timely manner.

Consideration will also need to be given to the implementation of all of the recommendations arising from the working group. While there may be some relatively simple improvements that can be made to the Bulletin Board that would not require a rule change, other more substantial changes may require amendments to be made to the rules. To this end, the Commission also intends to consider whether there are any informational gaps that fall within the scope of the COAG Energy Council's Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and which could therefore be dealt with in a more timely manner through this process. This is discussed further below.

DWGM review

As noted above, the Commission has been provided with an additional terms of reference specifically to undertake a detailed review of the DWGM. Over the second half of 2015 we intend to progress this as a standalone review, although there will be important linkages to the East Coast Review.

Through the DWGM Review we intend to consider whether the original objectives for the market in Victoria remain relevant in light of the changing broader east coast environment, and whether the current market design is achieving its objectives in an efficient manner.

A major area of focus for the DWGM Review will be to understand whether improvements can be made to the liquidity of trading and the pricing mechanism in the DWGM. In line with the Energy Council's Vision, we will consider the extent to which the DWGM can provide an efficient reference price and how this might be achieved. To do so may involve establishing whether energy prices can be separated from balancing and uplift charges, and assessing the effects of the current range of prices, including the intra-day rescheduling of the market. We will also consider the potential for harmonising the balancing element of the market with the design of the STTM and the commodity element with the GSH.

The other major element of this work will be to examine the potential to introduce capacity rights to the DWGM, with the objective of better facilitating market-led investment in network expansion. This would allow participants to signal the need for capacity augmentation, which would be likely to result in more efficient investment, and would transfer risk away from consumers to parties better able to manage it. The extent to which this facilitates inter-regional trade with adjoining markets will also be an important factor in our assessment.

We intend to commence this work with the publication of a paper for consultation in August/September 2015. This paper will further investigate the key areas of concern and clearly define the issues, as well as setting out some high level options for consideration. These options are likely to include incremental improvements, as well as more substantial changes such as those previously recommended for implementation by VENCorp[75] and options drawing on international experience.

Figure 3.9 below outlines the process regarding the outputs for the workstreams under the East Coast Review over the next six months, as well as those under the coincident DWGM Review.

Figure 3.9 2015 outputs under the East Coast Review and the DWGM Review

3.4.2 Issues that can be progressed in the shorter term

The Commission has given consideration to a number of issues that can be progressed over the short-term to assist the facilitated markets and pipeline frameworks to better achieve the NGO. These comprise:

- improving price transparency through the introduction of a wholesale gas price index by the Australian Bureau of Statistics (ABS);
- harmonising the start time of the "gas day", which currently varies across jurisdictions;
- removing the limitation in the National Gas Law on who can submit DWGM rule changes; and
- assessing the degree to which additional informational gaps fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and could be addressed under that process.

The Commission is of the view that these "no-regrets" measures can be implemented without undermining the second stage of our work to develop the medium and long term adjustments required in the east coast markets and pipeline frameworks to implement the Energy Council's Vision.

75 VENCorp previously operated the DWGM, and was one of the predecessor bodies to AEMO.

Improving price transparency

While some information on wholesale gas prices is available in the market, we consider that greater transparency would be useful as a transitional measure until there is an efficient reference price available to market participants and other interested parties. Our preferred approach is to work with the ABS to develop a survey-based gas price index that would measure the trends in prices payable under bilateral contracts over time.

This index would be compiled as an extension of the existing Producer Price Index by surveying large gas users who purchase gas directly from producers, including industrial users, gas-fired generators, retailers and LNG producers. While it would not reveal absolute price levels or provide an accurate indicator of gas prices by itself, the index would provide greater transparency around the direction and magnitude of changes in the price of confidential bilateral gas contracts.

Given that the prices payable under gas contracts have historically been linked to CPI, we would expect movements in the index to closely match movements in the CPI in the early stages. However, as existing gas contracts roll off in the next one to two years and new contracts are negotiated and captured by the index, we would expect movements to reflect pricing structures adopted in these new contracts, which may be linked to CPI and/or oil prices.

At any one time the index will be made up of a basket of gas contracts with different pricing structures that result in different individual price movements. Therefore movements in the index are unlikely to directly correspond to price changes in any single gas contract. However, the trend would provide greater transparency around the drivers of prices in gas contracts and allow users to develop a degree of understanding about how these drivers may influence prices in the future.

The AEMC has held initial discussions with the ABS about the introduction of such an index and understands that it would be possible for the ABS to compile and publish this on an ongoing basis. The next step in implementing the index will be for the AEMC to facilitate a workshop between industry and the ABS to discuss the methodology, data collection process, confidentiality arrangements and other issues.

Subject to the successful resolution of these issues, and active support from industry, it may be possible to introduce the index in the December 2015 quarter release (for publication end of January 2016), potentially including retrospective data going back a number of years.

Harmonising the gas day start times

Trading of gas is conducted over "gas days", and the timing of these currently differs across the east coast.[76] Harmonising gas day start times may remove some of the complexity for parties that operate across multiple markets and assist the process of

76 6:00am in Victoria, 6:30am at the Sydney and Adelaide STTM hubs, and 8:00am at the Brisbane STTM hub and Wallumbilla supply hub.

increasing the interoperability across all the facilitated markets. This would be likely to reduce transaction costs, and could therefore promote the NGO.

Submissions made to us in Stage 1 of the review have shown widespread support for such a change. Some parties have highlighted a number of one-off costs associated with implementing the change. However, it is also generally considered that these costs are likely to be less than the long term benefits that would result from a harmonised regime as the integration of the east coast market continues, although sufficient lead time would be required to implement necessary technical and contractual changes.

The nature of the Victorian market (in particular, the timing of reschedules in the DWGM) has led us to form a view that 6:00am would be most likely to minimise implementation costs, although few compelling arguments have been made as to what the harmonised start time should be. Consequently, we recommend that the Energy Council submit a rule change to the AEMC to change the gas day start time for the STTM hubs to 6:00am and to define the gas day start time for the GSH as 6:00am.[77] The assessment of the rule change request by the Commission will allow for further consultation on, and detailed consideration of, the exact gas day start time and the process for implementing this.

DWGM rule changes

Section 295(3)(a) of the NGL provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[78]

We note that this restriction was raised in both the 2013 Victorian Gas Market Taskforce review and the 2013 AEMC Gas Market Scoping study. In both reviews, stakeholders expressed concerns with the process of engaging with AEMO prior to a rule change being submitted. It was suggested that this represents a barrier for smaller market participants and potential new entrants to influence market development.

To address these issues, we recommend that the restriction be removed. All submissions made to this review addressing this issue have been supportive of this step. This would mean that any party would be able to propose rule changes applying to the DWGM, in manner consistent with the arrangements applying to the STTM, as well as those applying to the electricity sector through the National Electricity Rules.

Addressing additional information gaps

As noted above, the Commission will shortly begin its assessment of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change proposed by the COAG Energy Council. While the starting point for the Commission's assessment will be the Council's rule change request, we also intend to consider whether there are any other informational gaps that fall within the scope of the

77 Consequential changes to the exchange agreement are likely to be required to implement this change.

78 Victoria is currently the only adoptive jurisdiction.

proposed rule change[79] that could also be dealt with at this time. This could provide an efficient and timely way of addressing information gaps that require changes to be made to the rules.

The Commission intends to release a consultation paper on the rule change later in July 2015. The paper will raise the possibility of including suggestions made by stakeholders for additional information, such as data on storage facilities and volumes, data on linepack, as well as potential improvements to the medium-term capacity outlook information that Bulletin Board facilities are required to provide to AEMO.

79 The scope of the rule change has been described by the COAG Energy Council as rules "relating to the provision of gas pipeline flow and facility data that will: improve the operational management of facilitated wholesale gas markets; better inform the development of the GSOO; and enable a more accurate understanding of gas flows in Australia's eastern gas market and in turn allow a better representation of gas flows to be published on the BB". COAG Energy Council, *National Gas Rule Change Request and Proposal – Gas Transmission Pipeline Capacity Trading: Enhanced Information*, 30 March 2015, p. 3.

4 Transmission Pipeline Frameworks

Box 4.1 Summary of findings and recommendations

The ability of gas to flow to where it is most valued is inextricably linked to the conditions prevailing in the transmission segment of the supply chain. It is relevant therefore to consider whether the current regulatory and market arrangements applied to transmission are likely to support achievement of the Energy Council's Vision.

Based on our analysis, the submissions received to our Discussion Paper and Stage 1 Draft Report, and observations from earlier reviews, it would appear that there are some aspects of the current arrangements that are impeding the efficiency with which:

- secondary capacity is allocated and used on contract carriage pipelines;
- investment in transportation capacity occurs in the DWGM; and
- gas can be exported out of Victoria, which, in part, appears to stem from interoperability issues between the market and contract carriage models.

These issues are complex and will require more detailed analysis than can be achieved in Stage 1 of this review. We therefore intend to consider:

- the first of these issues in further detail in Stage 2 of the East Coast Review and the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change process; and
- the second and third issues in the DWGM Review and, to the extent relevant, Stage 2 of the East Coast Review.

As part of these more detailed reviews, we will also consider whether:

- the regulatory framework is still fit for purpose and is likely to remain so into the future given the changes underway in the market; and
- specific changes to the regulatory framework (including the third party access regime) may be required to improve the efficiency with which pipeline capacity is allocated, investment decisions are made in the DWGM and gas is traded and moved between jurisdictions.

4.1 Framework overview

Transmission pipelines enable gas to be transported under high pressure from production facilities to the entry point of a distribution system, or to users connected to the transmission pipeline.

Figure 4.1 Transmission pipelines in eastern Australia

Key: Major pipelines in bold. Blue = full regulation, Purple = light regulation , Green = 15 year no coverage

NSW

MSP – Moomba to Sydney Pipeline (APA) (half light)
EGP – Eastern Gas Pipeline (Jemena)
CRP – Central Ranges Pipeline (APA) (full regulation)
CWP – Central West Pipeline (APA) (light regulation)

SA

MAPS – Moomba to Adelaide Pipeline System (Epic)
SEA Gas Pipeline (APA 50%, Rest 50%)
SESA Pipeline - (APA)
SEPS Pipeline - (Epic)
Riverland Pipeline – (AGNL)

Vic

DTS – Declared Transmission System (APA) (full regulation)
Interconnect – (APA)
CHP – Carisbrook to Horsham Pipeline (Gas Pipelines Victoria)
SGP – South Gippsland Pipeline (Multinet)

Qld

RBP – Roma to Brisbane Pipeline (APA) (full regulation)
SWQP – South West Queensland Pipeline (APA)
QSN Link – Queensland, SA, NSW Link (APA)
QGP – Queensland Gas Pipeline (Jemena)
CGP – Carpentaria Gas Pipeline (APA) (light regulation)
BWP - Berwyndale to Wallumbilla Pipeline (APA)
WDD – Wallumbilla to Darling Downs Pipeline (Origin)
CBP – Cheepie to Barcaldine Pipeline
DVP – Dawson Valley Pipeline (Meridian and Westside JV)
NQGP – North Qld Gas Pipeline (Victorian Funds Mgt Corporation)
QCLNG Pipeline - (APA) (15 year no coverage)
APLNG Pipeline - (Origin, ConocoPhillips and Sinopec) (15 Year no coverage)
GLNG Pipeline - (Santos, PETRONAS, Total, KOGAS) (15 Year no coverage)

Tasmania

TGP – Tasmanian Gas Pipeline (TGP Pty Ltd)

Source: AEMO, 2012 Gas Statement of Opportunities. Amended to reflect the location of LNG facilities, ownership and regulatory status of pipelines.

Over the last 15 years there has been significant investment in this segment of the gas supply chain in eastern Australia, with 13 new pipelines constructed (including the Eastern Gas Pipeline, the SEA Gas Pipeline, the QSN Link and the three pipelines servicing the LNG facilities) and a large number of other pipelines undergoing expansion, or conversion into bi-directional pipelines. Some investment has also been carried out in storage facilities. These investments, which have occurred in response to firm long-term commitments by shippers, have facilitated the development of a more interconnected system in eastern Australia. In doing so, the investments have increased the supply options available to buyers in most major demand centres and facilitated a greater degree of inter-basin competition. The current degree of pipeline interconnection in eastern Australia can be seen in Figure 4.1.

Regulatory framework

The bottom of Figure 4.1 sets out the ownership interests and regulatory status of all the transmission pipelines in eastern Australia. As this information reveals, only 5.5 pipelines are currently regulated, three of which are subject to full regulation and 2.5 to light regulation.[80] The remainder are either unregulated, or subject to a 15 year no coverage determination. A brief overview of the third party access regime applying to transmission pipelines is provided in Box 4.2 (see Appendix D for further detail).

Box 4.2 Third party access regime and access regulation

The third party access regime and access regulation provisions applying to transmission pipelines are set out in the National Gas Law (NGL) and the National Gas Rules (NGR), which came into effect on 1 July 2008. Prior to 1 July 2008, pipelines were subject to the access regime and regulatory framework set out in the *Gas Pipeline Access (South Australia) Act 1997* and the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code).

The third party access regime adopted in the NGL and NGR largely mirrors the declaration and undertaking provisions in Part IIIA of the *Competition and Consumer Act 2010* (CCA). Under this regime, a pipeline can become covered and subject to either full or light regulation in one of the following ways:

- the pipeline was deemed a covered pipeline when the Gas Code came into effect;
- a coverage application is made to the National Competition Council (NCC) and the relevant Minister, having regard to advice from the NCC, is satisfied the pipeline meets all the coverage criteria in the NGL;
- an unregulated pipeline voluntarily submits an access arrangement to the AER; or
- the pipeline is developed through a tender process approved by the AER.

80 The three pipelines subject to full regulation are the Roma to Brisbane Pipeline, the DTS and the Central Ranges Pipeline. The 2.5 pipelines that are subject to light regulation are the Carpentaria Gas Pipeline, the Central West Pipeline and the Moomba to Sydney Pipeline from Marsden to Sydney (the remaining half of the Moomba to Sydney Pipeline is unregulated).

The access regime also provides for a pipeline's coverage status and form of regulation to change and 15 year coverage exemptions for greenfield pipelines if certain conditions are satisfied.

If a pipeline is covered then it may be subject to full or light regulation,[81] depending on the degree of market power the pipeline possesses and the likely costs of the two forms of regulation. The main differences between these two forms of regulation can be summarised as follows:

- Under full regulation, the pipeline operator is required to obtain the AER's approval for the price and non-price terms and conditions of access to the reference service(s) set out in the proposed access arrangement.[82]Although AER approval is required, the pipeline operator and users (or prospective users) are free to enter into a commercial agreement that differs from the access arrangement. If a dispute about access arises, however, the arbitrator is required to give effect to the approved access arrangement.[83]
- Under light regulation greater emphasis is placed on commercial negotiation and information disclosure, but provision has been made for parties to have recourse to the dispute resolution mechanism if negotiations fail. The pipeline operator is also prohibited under this form of regulation from engaging in conduct that may adversely affect access and/or competition in upstream or downstream markets.

If a pipeline is not covered, third party access can still be sought, but recourse cannot be had to the safeguards provided for in the NGL. An unregulated pipeline may also be required to provide AEMO with certain information for publication on the Bulletin Board or for the operation of the STTM.[84]

Market carriage and contract carriage models

There are currently two different models used to allocate and manage pipeline capacity in eastern Australia:

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81 The only exception to this is if the pipeline is a "designated pipeline". The DTS is the only designated transmission pipeline in eastern Australia. See Victorian Gvt Gazette No. S222m, 30 June 2009.

82 A reference service is defined in the rules as a service likely to be sought by a significant portion of the market. On the DTS the reference services are listed as injection, withdrawal and AMDQ services. On the RBP (which operates under the contract carriage model), the reference services are firm transportation service from Wallumbilla or Peat to Brisbane. If it could be shown that the "as available" service was sought by a large proportion of the users of the RBP then it could be classified as a reference service too but that is not currently the case.

83 See section 322 of the NGL. Note that while this section of the NGL is not limited in its application, in practice the ability to negotiate an alternative service only exists on contract carriage pipelines, because the DTS is operated on a simple injection/withdrawal basis. It is for this reason that all users of the DTS pay the reference tariff.

84 See sections 223 and 91FEA of the NGL.

- the market carriage model, which provides open access to the Victorian DTS and uses outcomes from the operation of the DWGM to schedule injections and withdrawals from the pipeline; and
- the contract carriage model, which is in use on all other pipelines and relies on bilateral contracts between the pipeline operator and shippers to allocate pipeline capacity.

One of the more fundamental differences between these two carriage models is that shippers using a contract carriage pipeline can reserve firm capacity on the pipeline through bilateral contracts, while shippers on the DTS cannot. Shippers on the DTS may, however, hold AMDQ or AMDQ Credit Certificates (jointly referred to as AMDQ), which provide certain financial and market benefits, and some limited physical benefits.[85]

Other key differences between these two carriage models are set out in Table 4.1 below.

Table 4.1 Differences between the contract and market carriage models

	Contract Carriage	Market Carriage
Pipeline characteristics	Traditionally point-to-point	Meshed network
System operator	Pipeline owner (pipeline operator)	Independent system operator (AEMO)
Services	Firm (or ranked priority), as available or interruptible transportation services, storage and loan services, overrun/imbalance services	Standardised injection/withdrawal services AMDQ CC
Means by which shippers access services	Bilateral contracts entered into with the pipeline operator, the majority of which involve the reservation of firm capacity	The DTS operates on an open access basis and shippers do not therefore have to enter into contracts with the pipeline operator. They just have to be registered as DWGM participants, enter into a payment deed with the DTS and connection agreement with distribution networks
How pipeline capacity is allocated on a daily basis	Daily nomination process - firm services are accorded a higher priority than as available or interruptible services when there are constraints. Unutilised contracted capacity can be traded by shippers or the pipeline operator	Through the DWGM gas scheduling process

85 AMDQ provides holders with a hedge against congestion uplift charges up to Authorised Maximum Interval Quantity and entitles the holder to higher priority than customer with no AMDQ if there is a tie in injection bids or if curtailment is required to maintain system security. See Appendix F for more detail on AMDQ.

	Contract Carriage	Market Carriage
Basis on which investment decisions are made	Typically underpinned by medium to long-term contracts with shippers, with shippers allocated firm capacity rights	Through regulatory process because shippers are usually unwilling to underwrite investments they cannot guarantee firm access to

Strengths and weaknesses of the market and contract carriage models

Both the market and contract carriage models have strengths and weaknesses.[86] For example, the market carriage model is said to promote both the efficient use of the DTS (ie, through the operation of the DWGM) and dynamic efficiency in other markets (ie, because it reduces barriers to entry), and circumvent the need for any secondary pipeline capacity market. The market carriage model may not, however, promote efficient and timely investment in the DTS because investment decisions are driven by regulatory processes rather than being market-driven (ie, because shippers cannot access firm capacity rights and are therefore unwilling to fund expansions).[87]

The contract carriage model, on the other hand, is said to:

- promote efficient investment in the pipeline and a better allocation of investment risks, because shippers can secure firm access rights to any capacity expansions they fund, and are in a better position to manage long term investment risk through commercial arrangements with gas producers and/or end-users; and
- allow more bespoke transportation and storage services to be offered to shippers than those available under the market carriage model.

The contract carriage model may not, however, promote the efficient use of the pipeline in the short-run when there is contractual congestion. Whether or not a contract carriage pipeline is utilised in the most efficient manner in these circumstances will depend on whether:

- firm capacity rights can be readily traded;
- parties have the incentive and ability to trade contracted but unutilised capacity (secondary capacity); and
- the transaction and coordination costs associated with entering into such a trade.

86 See for example, K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, pp. 112-113, Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, pp. 56-58 and Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, pp. 117-120.

87 This is because: the gas spot price facilitates access to the DTS by those who value access most highly; and use of the pipeline is unencumbered by contract capacity rights, which avoids problems associated with capacity trading, including difficulties in defining capacity and the potential exercise of market power by incumbent shippers or the pipeline owner. Note that because the DTS is operated on an open access basis there is also no scope for capacity hoarding.

At different points in time the strengths and weaknesses of these two models can become more or less important. For example, as capacity constraints emerge on a market carriage pipeline the effect of any delays in investment brought about by the fact that investment is regulatory driven rather than market driven become more acute. Similarly, when a contract carriage pipeline is fully contracted but not fully utilised the effect of any constraints on access to spare capacity become more acute.

Recent developments in the transmission segment

In order to accommodate the structural changes underway in the broader east coast Australian gas market the transmission network is becoming increasingly interconnected. This interconnection is being supported by significant investments, including:

- the QSN Link, SWQP, Moomba to Sydney Pipeline and Moomba to Adelaide Pipeline System,[88] which are being (or have been) converted into bi-directional pipelines to enable gas to flow from the Cooper Basin and Victoria to Wallumbilla and excess gas produced by the LNG facilities to flow into south eastern Australia;[89]
- the Roma to Brisbane Pipeline and Berwyndale to Wallumbilla Pipeline, which are being converted to bi-directional pipelines to enable gas to flow to and from Wallumbilla;[90]
- the EGP, which is being expanded to enable more gas to flow from Victoria to New South Wales and the ACT and may also be physically connected to the Moomba to Sydney Pipeline to enable gas to flow to other locations in New South Wales and Queensland;[91] and
- the DTS, which is being expanded to enable more gas from Victoria to flow into New South Wales and Queensland.

Some investment is also being carried out in the Wallumbilla Supply Hub to facilitate the movement of gas across the hub.[92]

These investments are allowing for more flexible and dynamic transportation and storage service offerings across multiple pipelines and will enable the direction of gas flows to change more rapidly in response to changes in demand and supply.

Apart from driving new investment, the changes underway in the market are also affecting the nature of the demand for transportation and storage services and the degree of flexibility sought by some market participants. For example:

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88 The MAPS pipeline is also being connected directly to the SEA Gas Pipeline.

89 AEMO, *2015 Gas Statement of Opportunities*, April 2015, p. 3 and APA presentation, *The changing face of gas transmission service*s, 18 September 2014.

90 APA website, http://www.apa.com.au/our-business/energy-infrastructure/queensland.aspx

91 Jemena, Submission to Stage 1 Draft Report, 1 June 2015, p. 1.

92 APA, *Annual Report 2014*, p. 3.

- LNG proponents and market participants that are able to respond relatively quickly to short-term changes in the availability of gas[93] are looking for flexible short-term services to transport or store gas across multiple pipelines and between multiple receipt and delivery points as and when required.

- Higher gas prices and uncertainty about the availability of gas are reportedly starting to have an adverse effect on the demand for gas and transportation services by some large industrial customers, which could adversely affect the utilisation of some pipelines.[94]

- Higher gas prices and weaker conditions in the NEM are also adversely affecting the demand for gas and transportation services by those gas fired generators that have been unable to take advantage of the lower priced "ramp" gas that has been available in the lead up to the commissioning of the LNG facilities.

Submissions to this review suggest that pipeline operators have responded to the changing needs of some segments of the market by:[95]

- offering more flexible and bespoke transportation and storage services and shorter term contracts to meet the needs of those shippers seeking a greater degree of flexibility;[96] and

- taking steps to facilitate the trade of contracted but unutilised capacity[97] and selling that capacity themselves on an "as available" basis.

Matters considered in the chapter

The transmission segment appears to have responded in a relatively dynamic way to the structural changes occurring in the market. However, some market participants and policy makers have questioned whether the current regulatory and market arrangements are sufficiently flexible to deal with future market conditions. Questions have also been raised about whether the arrangements are enabling gas to flow to where it is valued most, or if there are factors that are impeding:

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93 For example gas fired generators.

94 For example, BP announced in 2014 that it would be closing the Bulwer Island refinery in Brisbane. See Brisbane Times, Brisbane's job losses as BP refinery is closed, 2 April 2014.

95 APGA, Discussion Paper submission, March 2015, pp. 5-6, APA, Discussion Paper submission, 26 March 2015, p. 6, Jemena, Discussion Paper submission, 26 March 2015, Epic Energy, Discussion Paper submission, 27 March 2015, p. 2 and Origin Energy, Discussion Paper submission, 26 March 2015, p. 5.

96 For example, firm services are being supplemented with "as available" or interruptible transportation, storage, loan and other ancillary services. Ranked priority services are also being offered on some pipelines to provide a firm service outside peak periods. Greater flexibility is also reportedly being provided in terms of enabling changes to delivery and receipt points in existing contracts and allowing intra-day nominations.

97 For example, through the development of capacity trading platforms and other measures that are designed to reduce the impediments to capacity trading (eg in pipe trades or imbalance trades).

- the efficient allocation and use of contracted but unutilised pipeline capacity (section 4.2);
- the efficient and timely investment in transportation capacity, particularly in Victoria (section 4.3); and
- the efficient trade and movement of gas between jurisdictions (section 4.4).

Some parties have also questioned whether the regulatory framework is still fit for purpose given the changes underway in the market (section 4.5).

4.2 Efficient allocation of pipeline capacity

In a market of growing dynamism and uncertainty, contract lengths appear to be shortening and more options for trading are required. Until recently, market fundamentals were more predictable and long-term contracts were relatively effective. 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 pipeline capacity is allocated. This appears to be leading some stakeholders to advocate the adoption of measures that will increase the level of capacity trading on contractually congested pipelines.

Contractual congestion is said to occur when a contract carriage pipeline is fully contracted, but not fully utilised. A secondary capacity trade in this case could improve the efficiency with which gas is allocated if a shipper that does not have access to the capacity required to transport gas on a particular pipeline, values the capacity more than the holder of that capacity, and a trade occurs (see Box 4.3). Trades of this nature can lead to improved utilisation of existing pipeline capacity, provide market participants with a greater degree of flexibility and risk management options, and facilitate a greater degree of upstream competition. This type of trade may also reduce barriers to entry for prospective shippers, which may, in turn, have a positive effect on competition in downstream markets.

Capacity trading has also been highlighted in previous reviews[98] as an important area for reform because it is believed that it will:

- improve the efficient operation of contract carriage pipelines;
- provide market participants with a greater degree of flexibility to access cheaper sources of gas and to manage risks; and
- act as a conduit for upstream competition.

Some of the barriers to capacity trading that stakeholders have cited, include:

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98 See, for example: K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, 2013, p. 113, and Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015.

- prohibitive search and transaction costs for shorter-term trades and technical constraints on defining capacity rights; and
- the failure of primary capacity holders and/or pipeline owners to release capacity, which may occur for strategic reasons, or because the capacity holder places a higher value on the unutilised capacity than a prospective shipper.

These barriers are explored in detail in the remainder of this section.

Box 4.3 Capacity trading basics

If a firm capacity holder on a pipeline (primary capacity holder) has any spare pipeline capacity, it may decide to on-sell it to another shipper that is in a position to utilise the pipeline capacity. This secondary trade may take the form of either:

- a bare transfer, which results in the contract holder's rights (or part thereof) being temporarily transferred to the counterparty but the contract holder remains responsible for the financial and operational obligations in the agreement (such as pipeline nominations);
- a novation, which results in the contract holder's rights and obligations under the GTA being permanently transferred to the counterparty; or
- an operational capacity transfer, which provides for the temporary transfer of the contract holder's operational rights and obligations under the GTA.

The contract holder's willingness to enter into such a trade will depend on:

- how much spare capacity it has and the period over which it is available;
- the opportunity costs of not entering into the transaction;
- commercial considerations, such as the effect the transaction may have on the buyer's competitive position in a downstream market; and
- the transaction costs associated with entering into such an arrangement (ie negotiation and contracting costs and ongoing contract management costs).

The counterparty's willingness, on the other hand, will depend on whether:

- the counterparty is able to make use of the pipeline capacity, which will depend on its end-use requirements and contractual position;
- the period over which the capacity is to be supplied corresponds with the period over which the counterparty can use the capacity;
- the firmness of the capacity meets the counterparty's requirement; and
- the total cost of entering into the transaction (including price and any transaction costs) as compared to the cost of any substitute service.

Due to the confidential nature of these agreements, it is not possible to determine how frequently these types of transactions are used. Anecdotal evidence, however, suggests these transactions do occur but are not widely used.

In addition to being able to contract with the primary capacity holder, a prospective shipper may be able to enter a contract with the pipeline operator, who can sell any unutilised contracted capacity to other shippers on an "as available"[99] basis. Whether or not a counterparty will view an "as available" transportation service as a substitute for a bare transfer will depend on:

- whether the counterparty requires a firm service; and
- the price and other terms and conditions proposed by the pipeline operator.

4.2.1 Search and transaction costs

Prior transactions between two parties may allow subsequent trades to occur on a faster and lower cost basis than would otherwise have been the case. However, for a genuinely liquid market to develop, other measures may be required to reduce search costs and other transaction costs (eg contracting and negotiation costs), particularly for very short-term capacity trades.

For short-term capacity trades, search and transaction costs may be acting as an impediment to trade because shippers are unlikely to have the processes, such as standardised contracts, in place to quickly respond to these transactions.[100]

Participants' ability to engage in short-term capacity trading may similarly be limited by provisions in the primary capacity holders' contracts with the pipeline operator that restrict the ability or incentive to trade capacity, such as point-to-point delivery requirements, nomination cut-off times and other fees and charges. The fact that capacity rights are generally defined as being between a specific delivery point and receipt point appears to naturally limit the ability of participants to trade (as few participants are likely to have exactly the same requirements), particularly on pipelines with multiple receipt and delivery points.[101]

99 If there is spare uncontracted capacity on the pipeline, the operator can also compete to provide firm transportation service.

100 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 122.

101 The point to point nature of capacity rights may be more of an issue for industrial customers and gas fired generators because they have traditionally only sought to have gas transported from a receipt point to their facilities. Larger retailers, on the other hand, tend to enter into contracts that provide for the use of multiple delivery and receipt points. That being said, larger retailers may be limited in their ability to add further delivery (or receipt) points to accommodate a capacity trade if they haven't already specified those points in their GTA. They may also be constrained in their ability to transfer the capacity that they have reserved for a particular delivery (receipt) point to another delivery (receipt) point even if the delivery (receipt) point they want to transfer the capacity to is already specified in their GTA.

Recent developments in reducing search and transaction costs

Some steps have recently been taken to try to facilitate secondary capacity trading by reducing search and transaction costs.

Both APA and Jemena have established capacity listing websites, wherein participants can find one another through listing capacity bids and offers, and can thereafter perform capacity trades over the counter. APA's platform currently allows capacity on the South West Queensland, Carpentaria, Moomba to Sydney and Roma to Brisbane pipelines to be listed. The website includes other, basic information to facilitate the transaction. Jemena's platform allows capacity on the Queensland Gas Pipeline to be listed, and is expected to be expanded to include the Eastern Gas Pipeline.

In December 2012, the Energy Council commenced a process to consider whether further policy options could facilitate increased trade in transmission pipeline capacity in the east coast gas market. The final Regulation Impact Statement (RIS) on Gas Transmission Pipeline Capacity Trading was released a year later, in December 2013. This paper was subsequently endorsed by the Energy Council, which agreed to pursue the suggested enhancements to information provision and contractual standardisation. Specifically, the Energy Council endorsed:

1. the redevelopment of the National Gas Market Bulletin Board (BB) to improve the functionality and usability of the BB and the inclusion of a capacity listing service on the BB;

2. the development of voluntary standardised contractual terms and conditions applying to pipeline capacity; and

3. the submission of a rule change to the AEMC requiring pipelines and shippers (via pipeline operators) to provide information concerning pipeline capacity utilisation and capacity trading activity, to be published by AEMO.

Work on the first two items was completed by AEMO in 2014 and there is now a capacity listing site on the BB and a standard form Capacity Trade Agreement contract on AEMO's website. The AEMC received the Energy Council's Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change request on 30 March 2015. Further detail on the rule change can be found in Chapter 8.

In addition to these developments, APA has reportedly developed:[102]

- a standard GTA with standardised terms and conditions to enable shippers to trade capacity more readily through either a bare transfer or through assignment;

- standard contractual terms for its capacity trading service that can be inserted into any existing transportation contract and enable parties to trade firm capacity rights; and

102 APA, Discussion Paper submission, 2015, p. 23.

- an in-pipe trade service, which enables shippers to trade gas with other shippers irrespective of the physical receipt point using virtual receipt and delivery points.

We also note that the recently announced ACCC inquiry into the competitiveness of the wholesale gas industry will consider "transaction costs, information transparency and the competitiveness of, access to, and any restrictions on...gas transportation".[103] We intend to work and consult with closely with the ACCC given the complementarity of the analysis in the East Coast Review and the ACCC's inquiry.

Stakeholder submissions to Discussion Paper

There has been considerable engagement from stakeholders on secondary capacity trading across several review processes. As such we have considered previous submissions as part of our broader assessment of the issues in addition to submissions made in this review.

In response to the Discussion Paper, some stakeholders presented views that the current arrangements governing pipeline capacity are appropriate, and that the Energy Council's rule change and other reforms should be tested in the market before further reforms are implemented.[104] Other stakeholders, however, are of the view that further reform (ie over and above what is contemplated in the rule change) in this area is required and have identified a number of potential reforms, which range from:[105]

- greater information provision to reduce search costs and increase the degree of transparency in the market – some of which extends beyond the issue of capacity trading to include gas supply and the activities of LNG producers (see Chapter 8); to
- the establishment of a secondary capacity trading platform or another market based mechanism that enables trade to occur more effectively and without the need to enter into bilateral negotiations.

Some stakeholders also raised concerns about:

- technical and operational issues that may affect secondary capacity trading, such as contracting costs and point-to-point delivery points in GTAs;[106] and

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

104 Jemena, Discussion Paper submission, pp. 1-2; APA, Discussion Paper submission, pp. 20-22; APGA, Discussion Paper submission, pp. 5-6.

105 GDFSAE, Discussion Paper submission, p. 6.

106 In particular, AGL identified a number of structural issues that may restrict capacity trading and suggested that: delivery points in GTAs be grouped into zones to provides shippers with greater flexibility without diminishing the pipeline operators' capacity to manage the pipeline; pipeline operators provide the allocation at the delivery point as part of a standard service, instead of shippers having to negotiate an allocation agreement; and nomination cut-off times should not be based on operational requirements that favour the capacity of pipeline operators over that of shippers.

- the effect that administrative charges levied by pipeline operators and other fees in GTAs costs may have on the costs of entering into secondary trades.[107]

Stakeholder submissions to Stage 1 Draft Report

Stakeholders provided widespread support for capacity trading, although some differences lie within the specific issues identified that may be impeding secondary capacity trading, and the remedies to address them.

APPEA provided support for a market mechanism to trade capacity, noting that it is "fundamental to market development and must be a key feature of any reforms". APPEA supports transparency improvements that are interfaced with the facilitated markets, to enable more active trading of capacity.[108]

Alinta considered that, in theory, pipeline operators have an incentive to contract spare capacity with market participants, but in some circumstances this incentive can be undermined by minimum haulage arrangements, a lack of standardised contracts for small parcels of capacity, and a lack of clear settlement, nomination and other billing arrangements.[109] Alinta's submission notes that the key to liquidity at supply hubs is the ability to access transportation capacity.

APLNG considered that access to gas transportation was a "major hindrance" toward a liquid and competitive east coast gas market. It suggested the following be addressed in Stage 2:

- Only capacity trade through *novation* should occur. Due to the need for confidentiality in capacity rights, only the shipper and pipeline operator should be involved.

- Ease of transfer of transportation rights through flexible receipt and delivery points is critical.

- All capacity trades should be posted on the Bulletin Board, including the capacity amount, receipt and delivery points, term and price. This will enable an assessment of whether gas is being allocated its highest use.[110]

AEMO questioned the value of another capacity listing service, in addition to that which features as part of the Gas Supply Hub platform, in the absence of an underlying capacity trading framework.[111]

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107 AGL, Discussion Paper submission, p. 6. Santos, Discussion Paper submission, p. 7. Alinta Energy suggested that exposure to unknown additional pipeline charges can be difficult to manage (Discussion Paper submission, p. 8). Stanwell considered that excessive fees are often charged on intraday nominations by pipelines (Discussion Paper submission, p. 3).

108 APPEA, Stage 1 Draft Report submission, p. 11.

109 Alinta, Stage 1 Draft Report submission, p. 3.

110 APLNG, Stage 1 Draft Report submission, p. 2.

111 AEMO, Stage 1 Draft Report submission, p. 2.

Orora observed the lack of information available on the Bulletin Board, noting that it does not "display nominations and capacity on laterals".[112] It considered that there was no market mechanism to reallocate capacity from Orora's gas retailer to Orora. "Gas trading should be available to allow for this to take place relatively simply, and for minimal cost."[113]

Australian Paper contrasted the DWGM - which it suggested is the "most efficient and cost-effective method of transporting gas molecules" - with the arrangements outside of the DWGM. The impediments to obtaining capacity outside of the DWGM are "significant and, in some instances, have served to reduce market competition by rendering it impossible or uneconomic to transport gas from an otherwise competitive supply point to an end use point".[114]

4.2.2 Failure to release

The term "failure to release" is used in this context to refer to either:

- the primary capacity holders and/or pipeline operator choosing not to trade spare capacity; or
- a situation where the price at which the primary capacity holder or pipeline operator is willing to make capacity available is higher than the prospective shipper is willing to pay.

In the market for secondary capacity trading, a failure to release may occur when:

- competition for the provision of secondary capacity is ineffective, which could occur if:
  - there is only a single shipper on the pipeline that has contracted all of the pipeline's capacity;
  - the capacity that the pipeline operator can offer does not meet the prospective shipper's needs;
  - provisions in the pipeline operator's contracts with primary capacity holders, which limit its incentive and/or ability to compete with primary capacity holders for the provision of secondary capacity (eg terms that require the pipeline operator to rebate some or all of the revenue it receives from such sales to the primary capacity holders); and/or
  - provisions in the primary capacity holders' contracts with the pipeline operator that limit their ability or incentive to trade capacity (see section 4.2.1).

112 Orora, Stage 1 Draft Report submission, p. 2.

113 ibid.

114 Australian Paper, Stage 1 Draft Report submission, p. 3.

- the primary capacity holders decide to hold onto their capacity for strategic reasons because:
  - the primary capacity holder wants to gain a competitive advantage in an upstream or downstream market by withholding ("hoarding") capacity;
  - the capacity provides the primary capacity holder with an option value; or
  - the capacity sought by the prospective shipper is too small to justify the costs that would be incurred in entering into the relevant contracts.

Observations from previous reviews

That participants may hoard or withhold capacity was questioned in both the Scoping Study and the Productivity Commission's recent research paper, *Examining Barriers to More Efficient Gas Markets*. For example, the Scoping Study considered that:[115]

> "Shippers and pipeline owners should have an incentive[116] to sell any spare capacity and, in theory, should compete against each other to sell the capacity. The latter of these points is of particular importance, because while a shipper may appear to have little incentive to sell spare capacity to a downstream competitor, the fact that a pipeline owner can sell that same capacity on an 'as available' basis, should encourage the shipper to compete to supply the service and recover some of its fixed transportation costs."

The Productivity Commission also questioned whether withholding capacity is necessarily an act of market power, and suggested that what may appear to be inefficient hoarding of capacity may instead be "commercial behaviour that is consistent with outcomes from effectively competitive markets".[117] The Productivity Commission went on to add that "holders of firm capacity rights may also be retaining some spare capacity as a risk management tool in an environment of market uncertainty."[118] The latter of these points is likely to be of particular importance at present given the current market dynamics.

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115 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, 2013, p. 113.

116 A pipeline owner should have incentives to sell capacity because the capacity has already effectively been paid for by the contracting shipper (ie because transportation charges are largely fixed and are payable irrespective of the volumes transported), so it will derive additional revenue from the sale. A shipper's incentive will depend on the opportunity costs associated with not entering into the transaction (which can be quite high because transportation costs are predominantly fixed) and commercial considerations, such as the effect the transaction may have on the buyer's competitive position in a downstream market.

117 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 120.

118 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 49.

Stakeholder submissions to Discussion Paper

Several stakeholders raised the issue of failure to release, or capacity hoarding, in submissions to this review. For example, the Major Energy Users (MEU) suggested that interruptible capacity offered by pipeline operators may either be offered at a higher cost than firm capacity or not offered at all, and that in instances of hoarding, the shipper may be trying to prevent competition.[119]

Adelaide Brighton also raised concerns about the ability of retailers to restrict the supply options available to customers by acquiring all the capacity on some regional pipelines and laterals and suggested this be addressed by introducing a capacity trading mechanism.[120]

AEMO also advocated examining ways to improve the incentives for shippers and pipeline operators to make capacity available, particularly on a short-term basis.[121]

A number of stakeholders also discussed the price that should be payable for unutilised pipeline capacity, with some contending that the price should be based on the marginal cost of providing the capacity, while others contended it should be equivalent to (or set a premium to) the price of firm capacity. For example, APLNG suggested that "standard commercial terms based on a marginal cost basis would assist" in maximising the use of transportation capacity.[122] Epic Energy, on the other hand, stated the following:[123]

> “In an environment where there is excess capacity available on a pipeline...'As Available' services, if offered need to be priced at a level which reflects the economic costs associated with such a service. This price will be at a substantial premium to firm service, as it has substantially higher costs to the Pipeliner (and at a much greater risk) in providing it.”

Stakeholder submissions to Stage 1 Draft Report

There was a mixed response to the Stage 1 Draft Report in terms of failure to release. Several stakeholders raised this as an issue worthy of addressing, noting the lack of incentives on capacity holders to release spare capacity, which impacts the capacity utilisation and therefore efficiency of the transmission pipeline sector. Other stakeholders did not raise this as an issue, or focussed on reducing transaction costs and providing support for a capacity trading market.

APA suggested that the underlying nature of the east coast capacity market may impact its liquidity. For example, there is a "predominance of single pipeline industrial

119 MEU, Discussion Paper submission, p. 8.

120 Adelaide Brighton, Discussion Paper submission, p. 4.

121 AEMO, Discussion Paper submission, 2015, p. 3

122 APLNG, Discussion Paper submission, p. 2.

123 Epic Energy, Discussion Paper submission, p. 3.

shippers with little interest or demand for trading capacity, as they have long term needs for firm capacity met under existing contracts".[124]

APA and the APGA expressed views that the access regime for primary capacity should not be examined as a way of addressing issues related to the secondary capacity trading market. They claimed that capacity trading was occurring and suggested that action should be taken when the impediments to trading are clearly identified.[125]

AGL noted the importance of the transmission sector for efficient allocation of gas, and its support for an examination of the current regulatory framework and market arrangements. It highlighted that it intends to undertake internal work on capacity trading, including consideration of contractual and access issues or the potential to shift to an open access regime.[126]

APLNG noted the importance of incentives to encourage the release of spare capacity. "Whether it's done on a voluntary or mandated basis, history would indicate that existing capacity holders will need to be incentivised to increase the capacity utilisation of critical sections of infrastructure."[127] QGC also suggested a focus on "hoarding".[128] Specifically, focus should be given to understanding any "contractual impediments" to shippers/pipelines offering to sell unutilised capacity. "Anecdotally, we understand that provisions may exist that restrict the price at which pipelines can offer capacity to the market (ie if secondary capacity is offered to the market at prices below the long-term contract price, existing shippers are also entitled to adjusted pricing for shipped volumes)."[129]

The Major Energy Users (MEU) provided examples of claimed hoarding of pipeline capacity. The first involves a situation where a shipper has contracted all the available capacity on a pipeline, enabling a shipper to become a monopoly provider of pipeline capacity. This prevents users switching retailer and potentially allows the monopoly shipper to charge a monopoly price for the capacity.[130]

Another example is where the pipeline operator would not offer a shipper's spare capacity on an interruptible basis, as to do so could lead the shipper to reduce its contracted capacity, thereby disadvantaging the pipeline operator. In this situation, the pipeline operator either offers interruptible capacity at a premium to firm capacity, or does not offer it at all.[131]

124 APA, Stage 1 Draft Report submission, p. 6.

125 APA, Stage 1 Draft Report submission, p. 11.

126 AGL, Stage 1 Draft Report submission, p. 4.

127 APLNG, Stage 1 Draft Report submission, p. 2.

128 QGC, Stage 1 Draft Report submission, p. 4

129 ibid.

130 Major Energy Users, Stage 1 Draft Report submission, pp. 5-7.

131 ibid.

4.2.3 AEMC's Stage 1 findings

Based on our review to date, there appears to be substantial interest in improving capacity trading arrangements, and some unmet demand for capacity trading at present. It would also appear from our preliminary review that the existing arrangements are less than ideal and that more trades could occur, or could be expected to occur in the future, if some of the barriers outlined above were reduced.

There are further potential issues in pipeline capacity trading beyond search and transaction costs and failure to release. For example, on a point to point pipeline with multiple injection and withdrawal points, defining capacity rights and system operation may be especially difficult.

Secondary trading of pipeline capacity is a complex issue and will require more detailed analysis than can be carried out in Stage 1. The Commission therefore intends to consider the barriers to secondary capacity trading, and the measures that can be put in place to reduce these barriers and encourage greater competition for the provision of secondary capacity in further detail in Stage 2 of the East Coast Review. In doing so, we intend to carry out a closer examination of:

- whether search and transaction costs can be further reduced by putting in place additional measures to those contemplated in the Energy Council's proposed Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change;
- how any technical constraints on capacity trading may be addressed (including point-to-point delivery requirements);
- the significance of the failure to release issue and whether any measures (including those identified by stakeholders and those in place in other markets) may be required to encourage capacity holders and pipeline owners to make secondary capacity available and compete with each other for the provision of this service;
- the pricing of secondary capacity and the factors that are likely to affect the pricing of this service; and
- whether any changes may need to be made to the current market and regulatory arrangements to support capacity trading (see section 4.5 for further detail).

4.3 Timely and efficient investment in pipelines

As noted earlier, there has been significant investment in gas transportation infrastructure over the last 15 years. These investments, which have largely occurred in response to firm long-term commitments by shippers on contract carriage pipelines, have facilitated the development of a more interconnected system in eastern Australia and, in so doing, increased the supply options available to buyers in most major demand centres and facilitated a greater degree of inter-basin competition.

While investment appears to have occurred in a relatively timely and efficient manner on contract carriage pipelines, concerns have been raised by a number of stakeholders and prior reviews about the effect that the following factors may have on the timeliness and efficiency of investment in the DTS:

- the inability of shippers to obtain firm capacity rights under the market carriage model (see Table 4.1 and Appendix F.2.2);[132] and
- the regulatory investment process and the application of the investment provisions in the NGR to fully regulated pipelines (see Box 4.4).

These issues are explored in the remainder of this section.

Box 4.4 Investment provisions in the NGR

The investment related provisions in the NGR can be found in **rules 79-86.** These rules apply only to the three pipelines subject to full regulation (the Roma to Brisbane Pipeline, the DTS and the Central Ranges Pipeline).

Rule 79 sets out the matters that the AER must consider when determining whether or not capital expenditure incurred in the immediately preceding period and forecast capital expenditure can be considered 'conforming' capital expenditure and rolled into the capital base. Conforming capital expenditure is defined in rule **79(1)** as capital expenditure that would be incurred by a 'prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services' and is 'justifiable' on a specified ground.

Rule 80 allows the service provider to seek an advance determination from the AER on whether capital expenditure it proposes to undertake within the access arrangement period will meet the conforming capital expenditure criteria in rule 79.

Rules 81-84 set out how non-conforming capital expenditure can be treated under the NGR. While this capital expenditure cannot be rolled into the capital base, a service provider may still undertake this form of expenditure (**rule 81**). If it does so, it may:

- recover that expenditure, or a portion thereof, through a surcharge approved by the AER **(rule 83)** or a capital contribution **(rule 82)**; or
- include the investment (or a portion thereof) in a 'speculative capital expenditure account', which increases annually at a rate determined by the AER (**rule 84**).

132 The market carriage model provides open access to all shippers using the Victorian DTS. In order to access the system, shippers enter a Transportation Payment Deed to pay the owner of the DTS (APA) directly for their injections and withdrawals (use of the system), the price of which is regulated by the AER. Under the market carriage model, shippers do not have firm access rights to transport gas on the DTS. Shippers may, however, hold AMDQ which provides some financial and market benefits.

If a speculative capital expenditure account is established and the capital expenditure (or a portion thereof) is later found to satisfy **rule 79**, it can be rolled into the capital base.

Rules 85-86 contain the redundant asset provisions. **Rule 85** states that an access arrangement may include a mechanism that provides for:

- assets that cease to contribute in any way to the delivery of pipeline services to be removed from the capital base at the commencement of the next access arrangement period; and/or
- the costs associated with a decline in demand to be shared with users.

Before requiring or approving such a mechanism, the AER must take into account the uncertainty it would cause and the effect that would have on the service provider and users.

If a redundant asset later contributes to the delivery of services, it may be treated as new capital expenditure and added to the capital base under **rule 86**.

Observations from previous reviews

The Scoping Study, the Victorian Gas Market Taskforce, the Eastern Australian Domestic Gas Market Study and the Productivity Commission each noted that while significant investment has occurred recently, much of it had occurred on contract carriage pipelines and concerns remain about how the market carriage model affects investment in the Victorian DTS.

The Scoping Study considered that while the market carriage model appears to promote both the efficient use of the existing DTS infrastructure and dynamic efficiency in other markets, it may not be promoting timely and efficient investment in the DTS.[133] The Scoping Study also suggested the following issues with the market and regulatory arrangements in Victoria:

- intra-period investment opportunities permitted under the NGR are not being utilised; and
- the DTS pipeline owner may have an incentive to avoid or delay investment to derive additional revenue from the auction of higher valued AMDQ and storage at Dandenong LNG facility.[134]

In its recent report on barriers to more efficient gas markets, the Productivity Commission claimed that while all capital investments involve a lag between the time of final investment decision and when the capital becomes operational, delays beyond

133 K Lowe Consulting, *Gas Market Scoping Study,* A report for the AEMC, 2013, pp. 112-113.

134 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, 2013, pp. 112-117. The issue that the application of the AER's investment regulation to export-related projects may not take account of benefits outside of Victoria was largely dismissed in the Scoping Study, see pp. 116-117.

this lag can impose costs.[135] The Productivity Commission also noted pipeline owners' concerns that the regulatory arrangements under the NGL[136] may increase the risks associated with investing in pipeline infrastructure, and therefore inhibit capacity investments:[137]

> “It is clear that access regulation can affect investment incentives. If pipeline owners are uncertain about how regulation would be applied and if there are risks associated with the arrangements for determining regulated prices to expansion, the risks from investing in pipeline infrastructure could be compounded... Also if regulated rates of return are not expected to fully compensate investors for the risks incurred, investments may not proceed. ”

The last in-depth review of the DWGM, the Pricing and Balancing Review undertaken by VENCorp in 2004, recommended a "staged implementation of improvements to the Victorian gas market arrangements"[138] which included the introduction of:

- ex-ante intra-day pricing (Stage 1);
- transmission rights to underpin new expansions (and resolve congestion management) (Stage 2); and
- a number of hubs within the DWGM and biddable capacity rights (Stage 3).

Of the recommendations listed above, only ex-ante intra-day pricing has been implemented (in 2007).

Stakeholder submissions to Discussion Paper

APA, APGA, EnergyAustralia, Epic Energy, ERM Power and ESAA consider that while the contract carriage model provides for timely market driven investment, the regulatory and market carriage model may act as a barrier to timely and efficient investment in the DTS.

APGA in particular considered that market carriage arrangements in Victoria require access regulation and “stifle the ability for timely private investment, therefore imposing significant costs on the community.”[139]

As the owner of the DTS, APA expressed concerns about the effect of the regulatory and market arrangements in the DTS on investment, noting the “timing of new

135 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 108

136 For example, redundant asset provisions in NGR 85(1) and regulatory error in setting prices, terms and conditions for access to the expansion.

137 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 115.

138 VENCorp, Victorian Gas Market Pricing and Balancing Review Recommendations to Government, 30 June 2004, p. i.

investment in capacity follows the regulatory cycle, rather than the requirements of users."[140] APA also expressed concerns about the free-rider effect resulting from the 'socialisation' of investment costs in the Victorian system, noting the market carriage arrangements mean that:[141]

- existing users may have to contribute to the cost of expansion even if their transportation requirements are unchanged and they have already funded their capacity requirements;
- new users (or existing users seeking to transport additional volumes of gas) may not face the full cost of their decision to transport gas; and
- users with volatile demand (such as gas fired generators or shippers seeking to move gas across the system) are subsidised by users with more stable capacity requirements, such as industrial users.[142]

APA suggested that its most recent investments in the DTS[143]were made possible by bilateral contracting arrangements that were entered into outside of the market arrangements of the DWGM and should not be viewed as 'proof' that investment can be market driven under the market carriage model.[144]

APA also expressed concerns about the effect that the redundant asset and speculative capital expenditure provisions in the NGR can have on investment (see Box 4.4).[145]

The Group of Leading Energy Companies and Major Users (GLECMU) suggested that the "benefits of a single pipeline regulatory regime should be considered if the existing investment arrangements hinder market developments."[146]

In contrast, other stakeholders, including the AER, Lumo Energy and the MEU have questioned the materiality and veracity of claims that the regulatory arrangements are inhibiting investment.

In its submission, Lumo Energy stated that it "does not accept the view that the regulated model of transmission investment in the DTS is deterring the level and

139 APGA, Discussion Paper submission, p. 36.

140 APA, Discussion Paper submission, p. 12.

141 APA, Discussion Paper submission, pp. 14-15.

142 APA, Discussion Paper submission, p. 14.

143 In the current regulatory period (2013-17) APA has made investments on the South West Pipeline to allow for additional gas from Port Campbell (approximately $40 billion) and on the Interconnect for additional northbound gas flows at Culcairn ($160 million): APA, Discussion Paper submission, p.13 & APA *Annual Report* 2014, Transmission. http://annualreport2014.apa.com.au/sites/default/files/documents/2014/APA001%20APA%20Review%20Transmission.pdf

144 APA, Discussion Paper submission, pp. 13-14.

145 APA, Discussion Paper submission, p. 26.

146 Group of Leading Energy Companies and Major Users, Discussion Paper submission, p. 3.

efficiency of the timing of transmission investment."[147] Lumo Energy added that the deferral of the SWP expansion from the 2008-12 access arrangement period to the 2013-17 period highlighted the fact that the decision not to allow the investment in the earlier access arrangement period was correct:[148]

> "To the extent the relevant investment was uneconomical and failed the incremental revenue test…the option was still available for a market participant to put forward the funds to underwrite the investment shortfall in exchange for AMDQcc…The fact that a market participant failed to provide the investment shortfall…implies that the market was not ready for this investment to proceed."

The AER also noted that provisions in the NGR allow "a regulated pipeline owner to seek an approval binding on the regulator for a project at any time during a regulatory period."[149]

Stakeholder submissions to Stage 1 Draft Report

In addition to concerns about the timeliness and efficiency of investment outlined by stakeholders in response to our Discussion Paper, a number of stakeholders[150] offered additional observations on our findings in the Stage 1 Draft Report.

The MEU highlighted the resilience and reliability of the DTS, noting that consumers have not reported significant concerns with the performance of the DTS and that longer term constraints have been, and will continue to be, resolved through the existing regulatory arrangements.[151] APA, however, suggested that regulatory interventions that weaken the link between firm capacity and investment are likely to undermine future investment.[152]

In relation to the introduction of capacity rights in the DWGM, Origin, the ESAA and the MEU highlighted that they considered it would be important to preserve the existing framework of limited rights embedded in AMDQ and AMDQCC. The MEU noted that AMDQ on the DTS was initially allocated to consumers to maintain continued access to gas to ensure operational requirements were met.[153] While Origin identified that as AMDQCC is obtained and paid for through an auction process, it is important that shippers are still able to access the rights associated with the AMDQCC

147 Lumo Energy, Discussion Paper submission, pp. 12-13.

148 Lumo Energy, Discussion Paper submission, p. 13.

149 AER, Discussion Paper submission, pp. 3-4.

150 Particularly, APA, MEU, ESAA and Origin.

151 MEU, Stage 1 Draft Report submission, p. 4.

152 APA, Stage 1 Draft Report submission, pp. 7-8.

153 MEU, Stage 1 Draft Report submission, p. 4.

holdings that have already been paid for.[154] On this issue, APA considered that firm capacity rights are key to market-led investment, but cautioned:[155]

> "...attempts in the past to introduce capacity rights into the market have been stymied by the degree of complexity such a mechanism would add to an already very complex market."

AEMC's Stage 1 findings

The appropriate allocation of risks and timely and efficient[156]investment in infrastructure are, as noted in Chapter 2, key characteristics of workably competitive markets.

The market carriage arrangements in Victoria are such that shippers cannot obtain firm access rights for transportation of gas. The lack of exclusive rights to use any augmentation or expansion in the system means that shippers have little incentive to underwrite investments in the pipeline. Rather than decisions being driven by the market in Victoria, decisions on investment in the DTS are regulated by the AER. In contrast, shippers on contract carriage pipelines are able to secure firm access rights to the capacity expansions they underwrite with long term contracts, and investment decisions are driven by the market and underpinned by those contracts.[157]

In addition to the inability for the market to drive investment in Victoria, stakeholders and prior reviews also have expressed concerns about the potential for delayed investment in the DTS through the regulatory process. However, it is unclear at this stage whether these delays (real or perceived) are significantly impeding gas flows and if so, whether they are a result of a failing in the regulatory framework or the application of the regulatory framework.

We are aware that there are provisions within the NGR that enable investments that have not been approved by the AER to occur within the access arrangement period. For example, Rule 80 allows the pipeline owner to seek advance determination from the AER on proposed capital expenditure, while Rule 65 allows the pipeline owner to seek a variation to its access arrangements during the period. These provisions have not been utilised in the last two access arrangement periods and some have suggested this is because the demand for the investment has not been acute enough to require it the use of these provisions. However, we have not yet been able to confirm whether this is the case or if there is something else that discourages the use of these provisions.

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154 Origin, Stage 1 Draft Report submission, p. 4.

155 APA, Stage 1 Draft Report submission, p. 8.

156 Investments in gas pipelines are efficient when their total benefits exceed the full economic costs of investment and those investments are made in a timely manner.

157 However, the Productivity Commission notes that delays in investment are not limited to market carriage arrangements. Negotiations that underpin contracts between pipeline owners and contract holders to underpin capacity expansions or augmentations can take months to negotiate. Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 111.

Given the costs and other adverse effects that delayed investment can impose on market participants, and the potential complexity associated with the potential solutions, the Commission intends to consider whether the regulatory arrangements and market carriage model are providing for an appropriate allocation of risks and timely and efficient investment in the DTS in further detail in the DWGM Review over the second half of 2015. In doing so, we intend to consider:

- the materiality of the issue;
- the efficiency of the regulatory framework as a substitute for market-led investment; and
- potential options to address the issue, which could include introducing some form of transmission rights into the DTS, as contemplated by VENCorp in 2004, and/or making changes to the regulatory framework (see section 4.5).

4.4 Efficient trade and movement of gas between jurisdictions

Notwithstanding recent investments to allow for greater volumes of gas flow between jurisdictions, concerns have been raised about a number of specific constraints on Victorian exports, some of which stem from interoperability issues between the market and contract carriage models. Concerns have also been expressed about the effect that the operation of two pipeline carriage models and other factors (eg differences in gas specification on pipelines), may have on the efficient trade and movement of gas.

4.4.1 Constraints on exports out of Victoria

With more gas from the Cooper Basin expected to be directed to the LNG facilities in Queensland and the remainder of south eastern Australia expected to become more dependent on gas supplies from Victoria, it is relevant to consider whether the interaction between the market and carriage models or other market design factors may be impeding the efficient trade and movement of gas out of Victoria.[158]

Observations from previous reviews

In the Scoping Study, stakeholders cited a number of constraints on the ability of shippers to export gas from Victoria via the DTS, including:

- difficulties that shippers had previously had obtaining AMDQ for exports via Culcairn, which resulted in exports being more susceptible to the risk of curtailment;
- the cost and complexities of having to participate in the DWGM for those shippers that just want to export gas; and

158 As far as we can ascertain, there are no problems injecting gas into Victoria via Culcairn.

- constraints on exporting gas from the Gippsland and Bass basins to South Australia.[159]

Submissions to Discussion Paper

A number of stakeholders noted in their response to the Discussion Paper the steps that have been taken in the last two years by APA and AEMO to address some of the concerns that were raised in the Scoping Study about the ability to export gas via Culcairn, which have involved:[160]

- expanding the northbound export capacity of the Interconnect; and
- amending the Wholesale Market AMDQ Procedures to enable AMDQ at a system withdrawal point (eg Culcairn) to be aligned with the firm capacity rights on an interconnected pipeline (eg the MSP) for the purposes of any withdrawal tie-breaker.[161]

While these steps have been taken, APA expressed some concerns about:

- the potential for contracted AMDQ capacity at Culcairn to be "eroded" over time; and
- the way in which AEMO makes gas supply and allocation decisions when the security of the system is threatened, which results in exports being at greater risk of curtailment than demand within Victoria.[162]

Origin Energy voiced similar concerns to APA about the withdrawal capacity at Culcairn being directly affected by demand in the remainder of the DTS and exports being "more susceptible to curtailment than other forms of demand."[163] Santos also expressed concerns about the curtailment risk faced by shippers seeking to export gas via Culcairn and suggested this risk was particularly high in winter.[164]

The curtailment issue was also touched on by some other stakeholders, who suggested that while AEMO is required by the Victorian Gas Load Curtailment and Gas Rationing and Recovery Guidelines to consider whether an exporting party has an alternative source of supply before curtailing them, this may not occur in practice. Stakeholders added that the guidelines in their current form do expose exports to a

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159 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 91.

160 APA, Discussion Paper submission, pp. 14-15, AGL, Discussion Paper submission, p. 5, Origin Energy, Discussion Paper submission, p. 3 and APGA, Discussion Paper submission, p. 34.

161 In amending these procedures, AEMO suggested that the change would promote the efficient operation of the interface between the DWGM and interconnected facilities by allowing scheduling in the DWGM to align with firm contractual rights on interconnected contract carriage pipelines. AEMO, Notice to Participants of AEMO's Decision on Making the Wholesale Market AMDQ Procedure, 10 June 2014.

162 APA, Discussion Paper submission, p. 15.

163 Origin Energy, Discussion Paper submission, p. 3.

164 Santos, Discussion Paper submission, p. 6.

greater risk of curtailment than other loads that are of a similar nature but are located in Victoria.

While most of the submissions focussed on exports via Culcairn, a small number of stakeholders also noted there are constraints on exporting gas from:[165]

- the Gippsland or Bass basins to South Australia which stem from:
  - physical constraints on the DTS that limit the volume of gas that can be transported from the Gippsland and Bass basins across the DTS during peak periods;
  - differences between the pressure of the DTS and the SEA Gas Pipeline, which may give rise to additional pressure service costs; and
  - contractual constraints on the SEA Gas Pipeline, with all existing capacity on this pipeline currently contracted.
- the Gippsland basin into NSW via the EGP, because all the capacity on the EGP is currently contracted.

Submissions to Stage 1 Draft Report

APA was the only stakeholder to comment on constraints on Victorian exports in its response to the Stage 1 Draft Report. In short, APA stated that it supports further work being carried out in Stage 2 to investigate the remaining barriers to trading gas into and out of the DWGM and that such an investigation should examine the role AEMO plays as system operator, both in terms of system security and planning. Elaborating further on this, APA suggested that the way in which AEMO currently operates the DWGM is:[166]

> "...reducing the priority of flows out of the system both at the planning stage, and in the operation of the market, which creates real barriers to trading between the DWGM and interconnected pipelines."

AEMC's Stage 1 findings

As stakeholders have observed, many of the constraints on exports via Culcairn that were cited in the Scoping Study appear to have been alleviated through investment, AEMO procedure changes and other measures implemented by APA and shippers to overcome other hurdles posed by the DWGM and the interaction between the two models. Although these changes are expected to result in greater volumes of gas being exported via Culcairn in 2015, there are a number of other market design and interoperability issues that may impede the efficient trade and movement of gas between Victoria and other jurisdictions, including:

165 See for example, Adelaide Brighton, Discussion Paper submission, p. 4, Alinta, Discussion Paper submission, p. 8 and Epic Energy, Discussion Paper submission, p. 4.

166 APA, Stage 1 Draft Report submission, p. 9.

- The potential for contracted AMDQ capacity at Culcairn to diminish ('erode') over time as demand in the remainder of the DTS increases (ie because changes in demand in other parts of the meshed network affect capacity elsewhere in the system), which may result in either less exports over time, or the DTS capacity having to be continuously expanded to maintain contracted AMDQ capacity.[167]

- The costs and complexities of having to participate in the DWGM for shippers that just want to export gas out of Victoria, which may discourage exports via the DWGM, even if that is the optimal transportation route

- The planning review framework that is currently in place in the DWGM, which may not have adequate regard to exports out of the system.

- The curtailment arrangements in the DWGM,[168] which provide for the following in the event of a curtailment that is required to resolve a threat to system security:[169]

  (a) exports to customers outside Victoria that have an alternative source of gas supply are to be curtailed ahead of their counterparts in Victoria; and

  (b) exports to customers outside Victoria that do not have an alternative source of supply are to be curtailed in the same order as their counterparts in Victoria.[170]

While the curtailment arrangements appear appropriate from a system operation perspective, it is possible that they may discourage shippers that have access to alternative sources of supply from exporting gas through the DWGM even if that is the optimal export route. The AEMC also understands from stakeholder submissions that when the system is under threat, there may be a tendency to treat all exports as curtailable, irrespective of whether or not they have an alternative source of supply.

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167 Note that this issue does not appear to be unique to export related capacity expansions, rather it appears to be an issue for most expansions that occur within the meshed network.

168 Under AEMO's Gas Load Curtailment and Gas Rationing and Recovery Guidelines, exports are listed in the second category of customers (ie after Tariff D customers with either no AMDQ or that have used in excess of their assigned AMDQ) that will be constrained off, subject to "alternative gas supplies being available to export gas customers in the same categories as specified in the curtailment tables that have not been curtailed". While not well expressed, this provision appears to provide for export customers that have another source of supply, or would otherwise fall into the second category of customers (ie gas fired generators or customers with an interruptible supply contract), to be in the second group of customers to be curtailed. Export customers that only obtain gas from Victoria and do not otherwise fall into the second category of customers, on the other hand, should be curtailed in the same order as Victorian customers.

169 AEMO, *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*, 13 May 2010.

170 For example, a gas fired generator located in NSW that is supplied with gas via Culcairn should be treated in the same manner as a gas fired generator in Victoria.

Given the potential for these market design and interoperability factors to impede the efficient trade and movement of gas out of Victoria, we are of the view that there would be merit in investigating these issues further in the DWGM Review.

In terms of the constraints on exports of gas from the Gippsland and Bass basins into South Australia, it is unclear at this stage whether there is a significant amount of unmet demand for such exports at present, given gas can be supplied into South Australia from various fields in the Otway Basin. Nevertheless, we are of the view that the framework should not impede such flows should it become economic to export gas from Victoria to South Australia and will consider this potential constraint further in the DWGM Review.

4.4.2 Operation of two carriage models and other potential impediments to the efficient trade and movement of gas

As outlined earlier in the chapter, there are a number of perceived strengths and weaknesses of the market and contract carriage models. However, more generally, the existence of two types of carriage models may act as an impediment to the efficient trade and movement of gas across the east coast.

Observations from previous reviews

The Victorian Gas Market Taskforce suggested that different arrangements for access to pipelines across jurisdictions may "restrict the ability of parties to trade" and that more uniformity in this area would be "desirable".[171]

This issue was also considered in the Victorian Department of Economic Development's 2014 Energy Statement, which considered the potential for a new access regime and a single pipeline carriage model to be implemented throughout eastern Australia that would provide for:[172]

- non-discriminatory access to pipelines;
- a single set of rules or standard contracts governing access to pipeline capacity;
- arrangements that promote secondary trading of pipeline capacity and the sale of unused capacity by pipeline owners;
- clear and transparent information on the availability of pipeline capacity; and
- rules governing congestion management and potentially congestion pricing.

In a similar vein to the Victorian Energy Statement, the Eastern Australian Domestic Gas Market Study highlighted the potential for a single pipeline carriage model to be

171 Victorian Government, *Gas Market Taskforce*, Final report and recommendations, October 2013, p. 37.

172 Department of State Development Business and Innovation (Victorian Government), *Victoria's Energy Statement*, 2014, p. 58.

applied throughout eastern Australia. Elaborating on this further, the study observed:[173]

> "Open access to infrastructure under a market carriage model also involves trade-offs. While sometimes criticised for providing a weaker signal to investment, a strength of this model is that it may further encourage depth and liquidity in wholesale markets. Whether there is an alternative form of market carriage which could be more widely applied in Australia would require careful consideration and review...While the evidence does not suggest an immediate problem, given the changes in the east coast market it could be appropriate to review which model will best meet the future needs of the market."

The debate around which carriage model should be adopted if a single model is to be implemented throughout eastern Australia was also considered by the Productivity Commission. The Productivity Commission concluded that the relevant policy decision should not be viewed as a choice of one model over another. Rather, the "strengths and weaknesses of each model should be considered in the context of the expected future needs of Australia's gas markets."[174]

The Productivity Commission also considered that if the market carriage model was extended to the remainder of eastern Australia it could adversely affect investment at a time that it is required in the market and could also impose substantial costs on market participants if existing contractual rights had to be unwound.[175]

Another emerging issue contemplated in the ACCC's recently published issues paper for its East Coast Gas Inquiry, is the potential for different gas specification requirements on pipelines servicing Queensland to act as a barrier to the efficient trade and movement of gas in eastern Australia.[176]

Submissions to Discussion Paper

Stakeholders were divided on the question of whether a single pipeline carriage model should be implemented and if so, what that model should be. The advocates of a single pipeline carriage model included:

- Alinta, Stanwell, the MEU and Manufacturing Australia, who are of the view that there would be merit in considering whether the market carriage model (or a

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173 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, p. 101.

174 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 118.

175 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, pp. 105, 119.

176 ACCC, East Coast Gas Inquiry Issues Paper, 4 June 2015, p. 11.

similar open access model) can be extended into the remainder of eastern Australia.[177]

- APA and APGA, who consider there would be merit in considering whether the contract carriage model can be extended into Victoria, or to certain segments of the DTS (eg the South West Pipeline, the Longford Gas Pipeline and the Interconnect).[178]

Importantly, none of these stakeholders consider that change is required immediately. Rather, they view the change as a longer-term option. In contrast to the advocates of a single pipeline carriage model, Jemena, AGL, EnergyAustralia and GDF Suez Australian Energy (GDFSAE) do not consider that a review into the relative merits of the contract and market carriage models or a single pipeline carriage model is required.[179] Elaborating further on this, AGL considered that:[180]

> "…commencing this debate will prove to be unnecessary and ultimately a distraction, particularly given that gas markets operate successfully with a combination of elements of both market and contract carriage. However, it is appropriate for the Commission to investigate points of interface between the two systems, to ensure gas can be wheeled from point to point without hindrance."

EnergyAustralia was of a similar view to AGL and considered that given the two models are likely to continue to coexist, it is important that the two systems interact effectively.[181]

While Origin Energy did not make any specific comments on this issue in its submission, the following observations were made in its submission to the Productivity Commission's recent review of the barriers to more efficient gas markets:[182]

> "… a review of the carriage models may be appropriate to support the continued development of the gas market. This review should not presuppose one model is better than the other and therefore that the objective of the review is a transition to the perceived better model. Instead

177 Alinta, Discussion Paper submission, p. 7, Stanwell, Discussion Paper submission, p. 7, MEU, Discussion Paper submission, p. 5 and Manufacturing Australia, Discussion Paper submission, p. 7. Alinta made it clear in its submission that this was a longer term policy option and not something that was required immediately, while Stanwell stated that such reform should only occur if the benefits outweigh the cost and "appropriate transition allowances" are used to "protect existing property rights". Alinta, Discussion Paper submission, p. 7, Stanwell, Discussion Paper submission, p. 7.

178 APGA, Discussion Paper submission, p.41. and APA, Discussion Paper submission, p. 30.

179 Jemena, Discussion Paper submission, p. 6, AGL, Discussion Paper submission, p. 7, EnergyAustralia, Discussion Paper submission, p. 3. GDFSAE, Discussion Paper submission, p. 6.

180 AGL, Discussion Paper submission, p. 7.

181 EnergyAustralia, Discussion Paper submission, p. 3.

182 Origin Energy, Submission to the Australian Eastern Domestic Gas Market Study, 2014, p. 6.

it should focus on identifying the strengths and weaknesses of the two models and whether firstly, there is scope for consistency between the models and secondly, an evolutionary process to a single model is appropriate. An assessment of costs and benefits should also support any case for change."

Submissions to Stage 1 Draft Report

GDFSAE, the MEU and APA were the only stakeholders to comment on this aspect of the Stage 1 Draft Report.

GDFSAE considered that a more fundamental issue that needs to be considered in Stage 2 is whether the trade across eastern Australia is being limited by the requirement to reserve capacity in each location, differences in gas specifications on some pipelines, and other non-financial impediments.[183]

The MEU expressed some concerns in its submission about the "simplistic differentiation" between the relative benefits and detriments of the market and contract carriage models, and claimed that while investment is usually viewed as being more efficient under the contract carriage mode "this is a distortion of reality".[184] The MEU pointed to the following in support of this view:[185]

- augmentation under the contract carriage model tends to be only sufficient for immediate needs because there is little appetite for building surplus capacity, while under the market carriage model consideration is given to whether the development of surplus capacity is in the long term interests of users; and
- the requirement for individual shippers to pay for the capacity of the pipeline to be increased under the contract carriage model acts as a significant barrier to entry and ultimately results in lower utilisation of the assets.

APA also voiced concerns about the way the contract carriage model was characterised in the Stage 1 Draft Report and considered that the efficiency with which capacity is allocated in this model cannot just be judged by the level of secondary capacity trading, because it unduly focuses on short-term allocation decisions over long term decisions.[186]

AEMC's Stage 1 findings

As the discussion above highlights, there are some impediments that may be affecting the efficient trade and movement of gas both within and across jurisdictions.

In terms of the carriage models, it is clear from the preceding discussion that neither the market carriage model nor the contract carriage model is perfect and a movement

183 GDFSAE, Stage 1 Draft Report submission, p. 6.

184 MEU, Stage 1 Draft Report submission, pp. 7, 11-12.

185 ibid.

186 APA, Stage 1 Draft Report submission, p. 9.

from one to the other is likely to involve significant efficiency trade-offs. Consequently, any consideration of a single pipeline framework would need to consider alternatives that may balance these trade-offs differently to the existing carriage models. A decision to implement a single pipeline carriage model is also likely to:

- give rise to significant implementation costs and risks;
- have a number of practical implications for capacity rights, system and market operation, regulation, investment, competition in the transmission segment and in upstream and downstream markets, all of which would have to be considered; and
- give rise to a considerable degree of uncertainty and disruption in the market, which the AEMC is particularly conscious of given the changes underway in the market.

It follows from these points that the benefits of implementing a single pipeline carriage model would need to be quite substantial for a decision to be made to proceed down this path.

To date, we have yet to see any compelling evidence to suggest that:

- the existence of both the market and contract carriage models is currently acting as a significant impediment to the trade and movement of gas between jurisdictions, although it may be affecting the efficiency with which gas is traded and moved between jurisdictions;[187] or
- the benefit of implementing a single carriage model would be substantially greater than the benefit that could be achieved by addressing the perceived deficiencies in the two pipeline carriage models.

That is not to say that there would not be value in investigating the options for a single pipeline carriage model further. However, in the AEMC's view, this should form part of the longer-term strategic development element in Stage 2 of the East Coast Gas Review and more immediate attention should be given to addressing:

- secondary trading issues in the contract carriage model (see section 4.2);
- investment issues in the market carriage model (see section 4.3); and
- interoperability issues between the two models (see section 4.4.1).

This approach is broadly consistent with the approach that has been advocated by stakeholders and will enable a more strategic and detailed review of the options and the costs and benefits associated with each option to be undertaken without adding additional uncertainty or disruption into the market at a time when it is undergoing

187 Support for this view can be found in the fact that exports from Victoria via the DTS are occurring and are expected to increase from mid-2015. It can also be found in the submissions received from stakeholders that are actually exporting gas or are involved in the export of that gas.

significant structural change. As part of this review, we would expect to consider whether the proposed options fit within the existing third party access regime and if not, the changes that may be required in this area. We would also expect to take into account the views expressed by stakeholders in response to both the Discussion Paper and Stage 1 Draft Report.

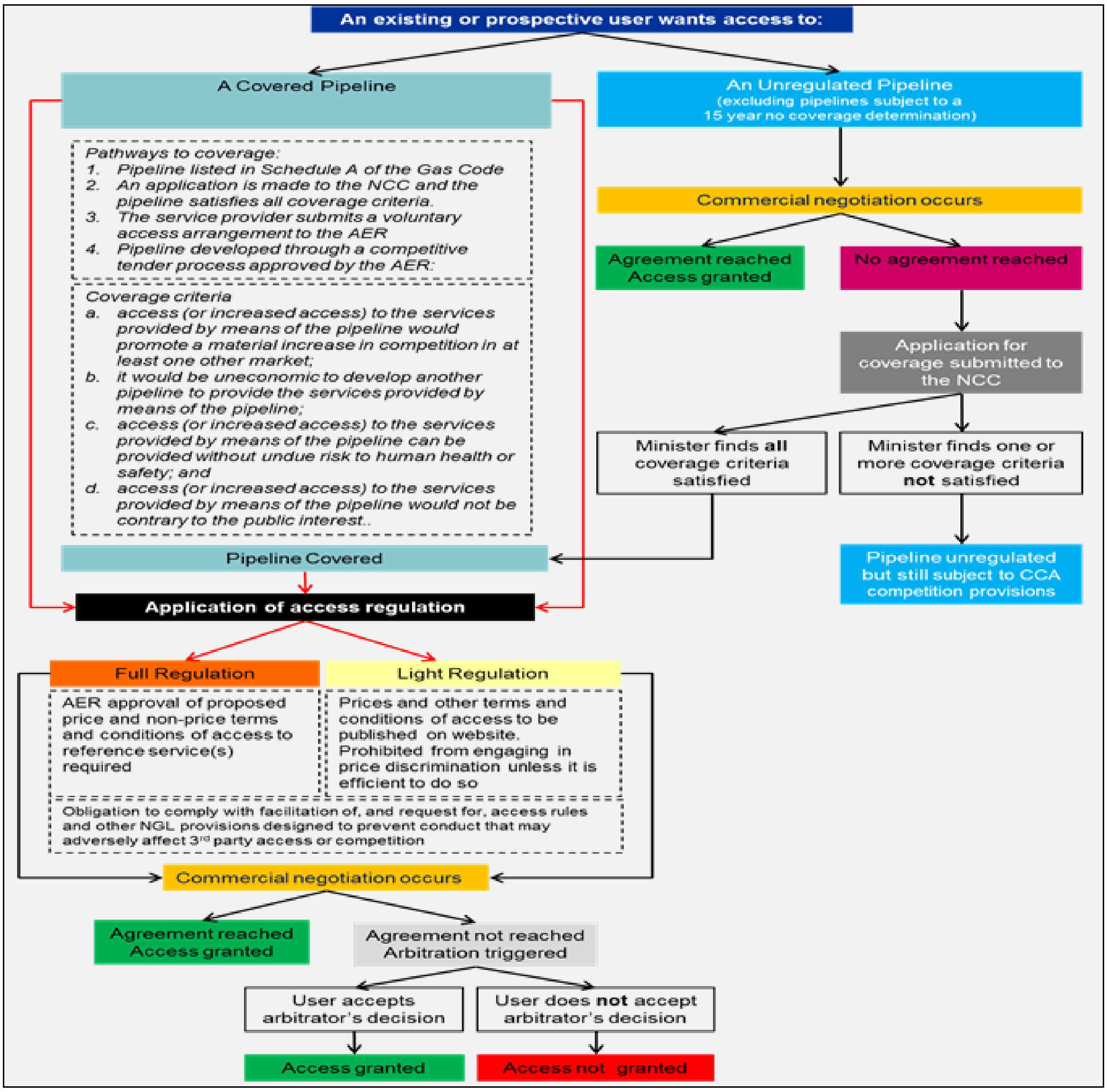
As part of this review, we also expect to consider the extent to which differences in gas specification on pipelines that are used to supply the LNG facilities (including the SWQP and QSN) may be affecting the efficient trade and movement of gas from southern sources into Queensland. Given the ACCC is looking into this issue, we intend to work closely with it to determine the extent to which this is an issue, the impact it is having on the market and how it may be addressed.

4.5 Regulatory framework

The third party access regime and access regulation provisions applying to transmission pipelines had its genesis in a series of COAG agreements in the 1990s, which culminated in the enactment of the *Gas Pipeline Access (South Australia) Act 1997* (GPAL) and the Gas Code in late 1997. In mid-2008 the GPAL and Gas Code were replaced by the NGL and NGR. A brief overview of the third party access regime applying to transmission pipelines is provided in Box 4.2, while Appendix D contains further detail.

The manner in which the third party access regime and access regulation operate under the NGL and NGR is depicted in Figure 4.2. Before examining this figure, it is worth noting that the arrangements for obtaining access to the DTS are somewhat different to those set out in this figure because it is operated on an open access basis and users or prospective users do not enter into bilateral contracts with the service provider.

Figure 4.2 Third party access regime



On the whole, the regulatory framework appears to have worked relatively well over the last 18 years and has been sufficiently flexible to deal with changing market conditions.[188] It also appears to have met many of COAG's original expectations for the regime, including supporting the efficient development and operation of an integrated pipeline network and promoting a competitive market for gas.[189] However, questions have been raised by some stakeholders about whether the regulatory framework is still fit for purpose given the changes underway in the market and whether it can support any measures that may be required to improve:

188 For example, with the advent of pipeline-on-pipeline competition in Sydney, Canberra and Adelaide, the regulatory status of the incumbent pipelines (the Moomba to Sydney Pipeline and Moomba to Adelaide Pipeline System) has changed to reflect the reduced ability of these pipelines to exercise market power.

189 National Third Party Access Code for Natural Gas Pipeline Systems, November 1997, p.1. Further detail on COAG's original expectations for the access regime can be found in Appendix D.

- the efficiency with which pipeline capacity is allocated (section 4.2);
- the efficiency and timeliness of investment in the DWGM (section 4.3);
- the efficient trade and movement of gas between and within jurisdictions (section 4.4 and hub services in Chapter 7).

Submissions to Discussion Paper

The views expressed by stakeholders about the regulatory framework were diverse, with a number believing the framework is working as policy makers intended, while others think there are some gaps in the current arrangements. A number of stakeholders also suggested the potential for more fundamental changes to the regulatory regime to support a greater degree of capacity trading, open access and/or investment.

Those stakeholders that consider the current framework is working as policy makers intended and are well placed to deal with the changes underway include APGA, APA and Jemena.[190] Santos also expressed a positive view on the regulatory regime:[191]

> "In the Australian context, we have seen a growth in the uncovered transmission pipeline networks, mainly due to the agility of the operators and shippers to work together to meet market demand. This shows that the market is working efficiently... If there were no pipelines being built or expanded even though there was demand for it, that would be a concern, this however is not the case."

The MEU, on the other hand, expressed some concerns about the:

- relatively high threshold embodied in the criteria that must be satisfied for a pipeline to become covered (the 'coverage criteria'), which it claimed "create a major hurdle to any objector";[192] and
- number of pipelines servicing regional industries and communities that are unregulated even though they are the only pipeline servicing these areas.[193]

Adelaide Brighton also voiced some concerns about pipelines servicing regional industries and considered that in some areas of South Australia a retailer had been able to restrict the supply options available to customers by acquiring all the capacity on some regional pipelines and laterals on the Moomba to Adelaide Pipeline System.[194]

190 APGA, Discussion Paper submission, p. 41, APA, Discussion Paper submission, p. 3 and Jemena, Discussion Paper submission, p. 1.

191 Santos, Discussion Paper submission, p. 7.

192 MEU, Discussion Paper submission, p. 7.

193 MEU, Discussion Paper submission, p. 7.

194 Adelaide Brighton, Discussion Paper submission, p. 4.

The following concerns about the regulatory framework were also raised by AGL in its submission to the Energy White Paper:[195]

> "In AGL's view, one key regulatory area requiring reform is better regulation of gas transmission network pricing. Even with increasing interconnection, the disparity of bargaining power between pipeline operators and shippers is leading to economically inefficient outcomes and negatively impacting market depth and liquidity...
>
> ...Most pipelines are 'uncovered', and not subject to economic regulation. While coverage, or the threat of coverage, theoretically operates as a constraint to pipeline operators in their commercial negotiations with shippers, pipeline coverage is actually hard to obtain and, once obtained, tends to lead to an access arrangement with only limited scope. "

Those stakeholders that consider more fundamental changes to the regulatory framework may be required include:

- the Victorian Department of Economic Development, who suggested that a new access regime (or code) be applied to all pipelines in eastern Australia and provide for non-discriminatory access to pipelines and a range of other measures to facilitate more capacity trading (see section 4.2);[196]
- Arrow Energy, who advocated the adoption of a single regulatory regime that provides clear mechanisms for accessing capacity;[197]
- BHP Billiton, who considered that as consolidation and increased interconnectivity takes place in the transmission segment there is "potential for inefficient transportation market outcomes" under the current framework and suggested a more uniform approach to gas pipeline regulation be considered, similar to that which applies in the UK and the US;[198]
- Manufacturing Australia, who supported the extension of regulation to all transmission pipelines to "ensure equality of access";[199]
- the GLECMU, who advocated the adoption of a "single pipeline regulatory regime with clear links between revenue and market outcomes" if the existing investment arrangements are found to hinder market development;[200] and
- Stanwell, who is of the view that the current framework "does not provide the right incentives for the efficient allocation of capacity or enough flexibility to

195 AGL, Energy White Paper submission, Attachment 1, 4 November 2014, p. 11.

196 Department of Economic Development (Victorian Government), Victoria's Energy Statement, 2014, p. 58.

197 Arrow Energy, Discussion Paper submission, p. 6.

198 BHP Billiton, Discussion Paper submission, p. 3.

199 Manufacturing Australia, Discussion Paper submission, p. 7.

200 Group of Leading Energy Companies and Major Users, Discussion Paper submission, p. 3.

promote an active short term market"[201] and suggested the existing framework be replaced with regulatory framework used in electricity.[202]

Submissions to Stage 1 Draft Report

The MEU, EUAA, GDFSAE, APA and APGA also made a number of other comments about the regulatory framework in their respective responses to the Stage 1 Draft Report.

As it did in its response to the Discussion Paper, the MEU expressed concern about pipelines that are not subject to any form of competition being unregulated and stated that the point of access regulation was to ensure that the owners of these types of assets could not extract monopoly rents from end users.[203] The MEU went on to add that the AEMC should:[204]

- consider whether the current application of the access regime is meeting the requirements of the NGO; and
- recommend that unregulated pipelines that are not subject to competition be reassessed to determine whether they should be regulated.

The EUAA stated that one problem with the current framework is that it has not been certified as an effective regime and called upon State and Territory governments to do so.[205]

GDFSAE stated that it welcomed the proposed assessment of participants concerns around monopoly services, and the role of regulating pipeline investments inside hubs.[206]

APA expressed some concerns about the suggestion that the access regime, which currently applies to primary capacity on a pipeline, could be extended to encompass secondary capacity as reflected in the following statement:[207]

> "APA does not believe that the primary market's access regime is the appropriate location for such intervention, as the access regime regulates the relationship between the pipeliner and the shipper, not the relationship

201 Stanwell, Discussion Paper submission, p. 3.

202 ibid.

203 The pipelines that the MEU cited in this context were the SEPS, which is used to transport gas from Katnook to Mt Gambier and the Angaston and Whyalla laterals on the Moomba to Adelaide Pipeline System.

204 MEU, Stage 1 Draft Report submission, pp. 12-13.

205 EUAA, Draft Report submission, p. 4. The AEMC understands that this issue was recently considered by the Productivity Commission as part of its review into the National Access Regime and it concluded that, on balance, the costs of certifying the gas and electricity regimes may outweigh the benefits. Productivity Commission, National Access Regime, 25 October 2013, p. 23.

206 GDFSAE, Stage 1 Draft Report submission, p. 6.

207 APA, Stage 1 Draft Report submission, pp. 12-13.

between shippers, which is the locus of the secondary capacity trading market."

Like APA, the APGA stated that the current access regime applies to primary firm capacity and added while it supports the development of a secondary capacity market it "cautions against changes to the access regime in order to achieve it".[208]

AEMC's Stage 1 findings

The AEMC understands from the comments set out above that while the regulatory framework has worked relatively effectively to date, there may be some gaps in the current framework that warrant closer attention, particularly given the changes underway in the market and the increasing interconnectedness and concentration in this segment of the supply chain. We are therefore of the view that there would be value in considering, as part of the Stage 2 review, whether the current regulatory framework is still fit for purpose and likely to remain so into the future given the changes underway in the market and potential future developments.

This consideration will be guided by the National Gas Objective[209] and the assessment framework set out in Chapter 2 and will consider the extent to which:

- The current framework is constraining, either directly or indirectly,[210] the incentive and/or ability pipeline owners may otherwise have to exercise market power in relation to pipeline and/or hub services in those cases where:
  - competition for the provision of these services is either absent or ineffective; and
  - the pipeline owner's market power is not otherwise constrained by the threat of entry, the existence of substitutes and/or the countervailing power of users.
- Changes to the current framework may be required to improve the efficiency with which:
  - secondary capacity is allocated on contractually congested pipelines (eg measures to reduce the barriers to capacity trading and/or facilitate a more transparent and competitive market for secondary trading);
  - investment decisions can be made in the DWGM; and
  - gas can be traded and moved between and within jurisdictions (eg measures to address interoperability issues between the market and contract carriage models and provide third party access to hub services).

208 APGA, Stage 1 Draft Report submission, p. 6.

209 Section 23 of the National Gas Law.

210 Either through direct regulation or the threat of regulation.

In considering these issues, we intend to work closely with the ACCC's East Coast Gas Inquiry team because, in contrast to the AEMC, the ACCC's information gathering powers are quite broad. It is therefore better placed than the AEMC to test, for example:

- whether any owners of unregulated pipelines or providers of hub services may be exercising market power, as has been suggested by some stakeholders; and
- the extent to which shippers and pipeline owners are competing for the provision of secondary capacity, whether there are any specific terms in GTAs that may be impeding the incentive and/or ability that shippers or pipeline owners have to sell secondary capacity and if any hoarding is occurring.

The ACCC's findings on these issues will help to inform our consideration of whether any changes to the regulatory framework are required and the nature of any such changes.

Making changes to the current regulatory framework may be quite challenging given the way it currently operates. Some of the challenges that could be faced are outlined in the box below.

Box 4.5 Challenges posed by the current regulatory framework

While some of the proposed changes to the regulatory framework outlined above could be made within the confines of the existing regulatory framework (eg measures to deal with investment issues in the DWGM), other measures (eg secondary capacity trading or hub services related measures or a new open access regime), may require more extensive changes because:

- the regulatory framework currently only provides for covered pipelines to be subject to any form of economic regulation, so the ability to impose obligations on shippers that have access to primary capacity, or access related obligations on unregulated pipelines, is currently constrained; and
- it is unclear whether the coverage provisions in the NGL currently extend to hub services (eg compression and redirection services).

On the first of these issues, it is worth noting that of the 27 transmission pipelines in eastern Australia, only 5.5 are currently covered[211] and the remainder are unregulated.[212] This would suggest that any decision to implement a mandatory secondary trading obligation on pipeline owners or a mechanism such as the oversell and buyback regime could only be applied to the 5.5 pipelines that are

211 Of the 5.5 pipelines that are covered, three are subject to full regulation (the Roma to Brisbane Pipeline, the DTS and the Central Ranges Pipeline) and 2.5 are subject to light regulation (the Carpentaria Gas Pipeline, the Central West Pipeline and the Moomba to Sydney Pipeline from Marsden to Sydney (the remaining half of the Moomba to Sydney Pipeline is unregulated)).

212 Appendix D provides further detail on why coverage has been revoked on a large number of pipelines.

currently covered. While it is possible under the NGL for unregulated pipelines to become covered,[213] this can only occur if the pipeline satisfies all the coverage criteria (see Figure 4.2). The threshold for coverage is currently quite high, so the prospect of more pipelines becoming covered appears quite low, under the current application of the test.[214]

The coverage threshold embodied in section 15 of the NGL is consistent with the threshold for declaration under Part IIIA of the CCA and the height of the threshold has, as noted by both the Productivity Commission and the Competition Policy Review Panel, been designed to confine the application of the access regulation to:[215]

> "...exceptional cases, where the benefits arising from increased competition in dependent markets are likely to outweigh the costs of regulated third-party access."

The threshold for coverage could become even higher in the future if the Competition Policy Review Panel's suggested amendments to Part IIIA[216] of the CCA (see Appendix D.3.4) are accepted by the Australian Government, and the Energy Council decides to make equivalent changes to the NGL.[217]

It may not therefore be possible to implement some of the measures stakeholders have suggested unless more fundamental changes are made to the third party access regime by. Such changes might include, for example, introducing an alternative form of regulation that can be applied to all pipelines, irrespective of whether they satisfy the coverage criteria, or amending the coverage criteria.

The discussion in Box 4.5 should not be construed as the AEMC having already formed a view that the existing regime needs to change. Rather, it is intended to highlight the constraints within the existing regulatory framework that would need to be considered when deciding what, if any, changes may need to be made to the current framework.

While it is possible that the constraints in the existing framework could be altered, we are aware that this would constitute a fundamental change in the current arrangements and would need to be carefully considered given both:

213 The one exception to this is pipelines that are subject to a 15 year no coverage determination.

214 The threshold is high because all four criteria must be satisfied and criterion (a) requires access to promote a material increase in competition in another market.

215 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review* Final Report, March 2015, p. 431 and Productivity Commission, National Access Regime, 25 October 2013, p. 2.

216 Harper, I., et al., *Competition Policy Review* Final Report, March 2015, pp. 73-74.

217 Whether or not a higher threshold for coverage is appropriate is something that would need to be carefully considered by the COAG Energy Council, particularly given: the concerns raised by both the MEU and AGL about the height of the current threshold and the extent to which the threat of regulation really does constrain a pipeline owner's behaviour; and the effect that the increasing degree of concentration and interconnection in the transmission segment and the movement away from the traditional point-to-point services (which together with the increasing interconnection

- the principles set out in COAG's Competition Principles Agreement; and
- the views that have recently been expressed by the Productivity Commission,[218] and the Competition Review Panel[219] about the circumstances in which access regulation should be applied.

We are also cognisant of the fact that regulation:

- is a second best option to competition; and
- is neither perfect nor costless, and that to the extent that the same outcomes can be achieved through industry led initiatives this should be pursued.

We intend therefore to consider any proposed changes to the regulatory framework having regard to both the NGO and the COAG's Principles of Best Practice Regulation, which in short, require:

- the market failure[220] or deficiencies in the existing framework to be clearly identified; and
- a rigorous and transparent assessment of the set of feasible policy solutions (including regulatory, self-regulatory, co-regulatory and non-regulatory options) to be conducted.

may give rise to greater network externalities) may have on the ability that some pipeline owners have to exercise market power.

218 Productivity Commission, *National Access Regime (2013)*, 25 October 2013, p. 2.

219 Harper, I., et al., *Competition Policy Review* Final Report, March 2015, pp. 73-74.

220 The term 'market failure' is used in this context to refer to a situation in which the market, left to its own devices, is unable to allocate resources efficiently.

5 Short Term Trading Market

Box 5.1 Summary of findings and recommendations

The STTM was conceived in 2006 when the only wholesale spot market for gas in Australia was the DWGM. At the time, governments identified the need to increase market transparency and provide participants with additional options for pricing imbalances and trading incremental gas outside of bilateral contracts.

The Adelaide and Sydney STTM hubs are generally regarded by participants as providing an effective gas balancing service and means of facilitating trade at demand centres, although views on the usefulness of the Brisbane STTM are mixed. Nonetheless, the prevalence of bilateral contracts and the mandatory nature of the STTM results in only a relatively small portion of total gas "traded" on the market benefiting from the centralised market arrangements.

The emergence of the GSH at Wallumbilla, coupled with the structural change in supply and demand resulting from LNG exports in Queensland, suggests it is an opportune time for reflection on the role of the STTM in the broader east coast gas market, as well as the facilitated markets more generally. In particular, we consider there is merit in considering whether:

- the originally stated STTM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and
- if not, whether the objectives and design of the STTM need to be re-focussed, taking into account developments in the broader east coast market and the STTM's role alongside the DWGM and gas supply hub.

The Commission will progress these issues in Stage 2 of the review. This will involve publishing a Discussion Paper for consultation that outlines the characteristics of different gas market designs and potential structures that could be implemented to meet the Energy Council's Vision. A technical working group will also be established to provide the Commission with expert advice as it finalises its recommended approach to wholesale market design for the Stage 2 Draft Report in December 2015.

With respect to recommendations that can be implemented more immediately, the Commission considers that harmonising the three spot market gas day start times would reduce compliance costs and the complexity of operating across multiple hubs, and is therefore likely to promote the NGO.

The Commission recommends the Energy Council propose a rule change to move the STTM gas day start times to 6.00am and to define the GSH gas day start time in the NGR as 6.00am, in line with the arrangements for the DWGM (noting further consideration of the time will occur during the rule change process).

5.1 Market overview

This section provides an overview and background to aspects of the STTM relevant to the issues considered throughout this review. It covers the original objectives for establishing the STTM hubs, key design features, as well as how the markets operate in practice. A detailed appendix on the design of the STTM is set out in Appendix E.

Market objectives

The STTM was implemented in Adelaide and Sydney in September 2010 and Brisbane in December 2011. It was part of a package of reforms by the Ministerial Council on Energy (MCE), which also included the National Gas Services Bulletin Board, Gas Statement of Opportunities and the establishment of a national gas market operator.[221]

In recommending the establishment of the STTM, the Gas Market Leaders Group, an industry-led body established by the MCE, set out the following objectives for the market:[222]

- Establish a mandatory price-based balancing mechanism for gas delivered and withdrawn from defined market hubs, replacing existing gas balancing arrangements at delivery points within hubs.
- Facilitate gas trading on a daily basis at market driven short-term prices.
- Provide price signals and facilitate secondary trading between shippers and users, and to facilitate greater demand side response.[223]

Taking into account these objectives, the STTM was designed as a day-ahead market for the trade of wholesale gas at the point of entry to distribution networks. STTM hubs are used for:

- providing a competitive service for participants to manage daily gas imbalances; and
- commodity trading.

Market design

STTM hubs in Adelaide and Sydney are supplied by two transmission pipelines, while the Brisbane STTM hub is supplied by one transmission pipeline, as shown in Figure 5.1. In order to trade gas through the STTM, participants must be able to demonstrate

221 The national gas market operator became AEMO, which assumed the functions of the state-based Gas Market Company, Retail Energy Market Company and gas functions of the Victorian Energy Market Corporation.

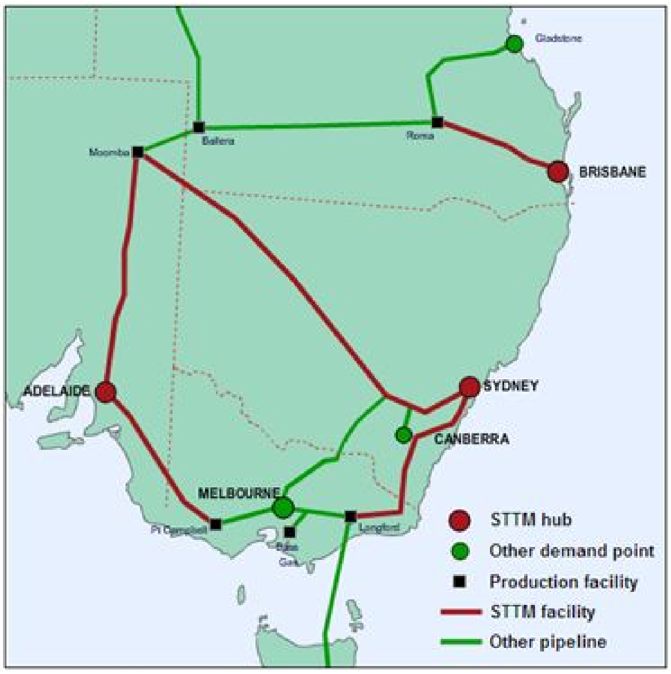
222 Gas Market Leaders Group 2006, *National Gas Market Development Plan,* Gas Market Leaders Group report to the Ministerial Council on Energy, Canberra, p. 23.

223 "Shipper" is the term used for a participant that transports gas through a transmission pipeline between production and demand centres.

to AEMO that they have contractual arrangements in place with pipeline operators to transport gas to the hub and/or withdraw gas from the distribution network.

Unlike the DWGM, AEMO manages the market but has no role in operating the pipeline and storage infrastructure, which is operated and scheduled by the infrastructure owners.

Figure 5.1 STTM hubs are located at Adelaide, Brisbane and Sydney



Source: AEMO.

Due to the physical characteristics of natural gas, and the time it takes to flow through transmission pipelines, nominations are made to producers and pipeline operators the day before gas is required.[224] Given this, and the objectives of the market, the STTM design was based around two broad elements:

- **an ex ante commodity market** – where supply and demand is matched for the following day and an ex ante price is determined by the market operator;[225] and
- **an on-the-day balancing mechanism** – to account for deviations on the gas day between the supply and demand schedules determined in the ex ante market and to ensure system security is maintained.[226]

224 In Victoria, gas is typically produced and delivered within 6 – 8 hours due to the close proximity of the gas fields to demand centres. In contrast, gas delivered from the Moomba into Sydney can take 2 – 3 days.

225 In this context, ex ante refers to transactions that occur the day before a commodity is traded.

226 In this context, system security refers to transmission and distribution pipelines operating within their pressure tolerances.

The ex ante commodity market is where shippers offer to supply gas and users bid to purchase gas for delivery the following day.[227] Offers and bids can be submitted to AEMO up until 12.00pm the day before the gas day in Adelaide and Sydney, and up until 1.30pm in Brisbane.[228]

The on-the-day balancing mechanism of the STTM is arguably its primary role in the broader east coast gas market. Without the STTM or another form of balancing market, pipeline operators would balance the system under a service negotiated as part of the bilateral contracts with their customers.

Market Operator Service (MOS) is the STTM's on-the-day balancing mechanism and is essentially a pipeline capacity service. Shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand or supply gas if flows to the hub are below demand (also known as bank and borrow or park and loan). MOS is procured through a competitive process each month by AEMO from shippers with contracts on STTM-connected transmission pipelines. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges (as discussed in section E.2.4).

A range of physical gas market participants, such as retailers, gas-fired generators and large industrial users transact through the STTM, while no financial institutions are currently registered at any of the STTM hubs. The number and type of participants currently registered at each hub are set out in Table E.4.

Market operation

Trades on the STTM can be categorised as:

- ex ante - gas traded between different entities;
- ex ante within participant - gas traded between the same entity; and
- ex post deviation - balancing deviations during the gas day.

Figure 5.2 shows that around 85 per cent of transactions across the Adelaide and Sydney hubs are within-participant, while for Brisbane 95 per cent of trades are within-participant. Most trades on the STTM are within-participant due to:

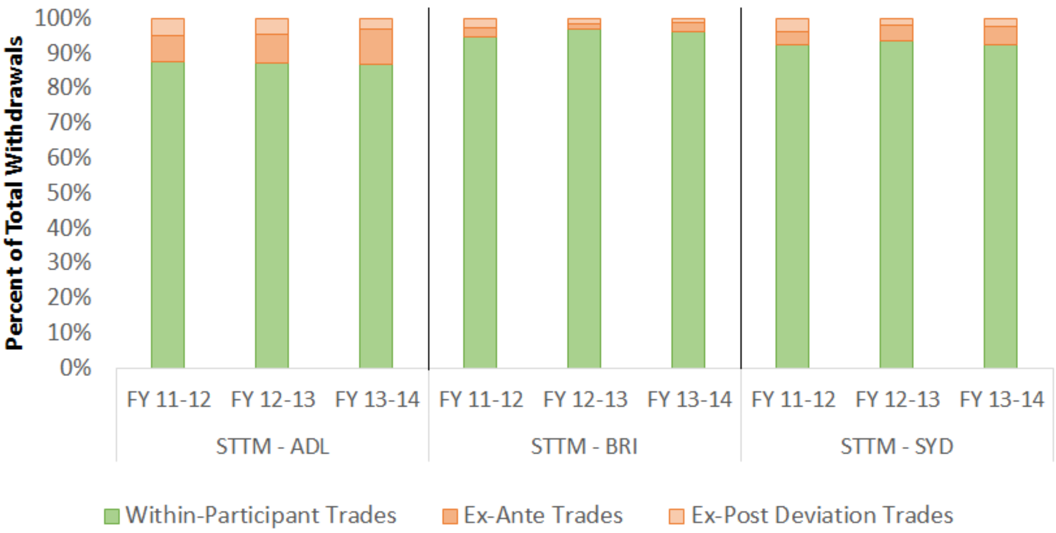
- the majority of gas on the east coast being procured outside the STTM through long term bilateral contracts; and
- the fact that all gas delivered to the hub is required to be transacted through the STTM, which results in the same entity having to sell gas into the ex ante commodity market and purchase it back each day.

227 STTM shippers deliver gas to be sold into the market and STTM users buy gas for consumption.

228 The variation in timing is due to differences in gas day start times at the hubs. The Brisbane hub operates from 8am EST while Sydney and Adelaide operate from 6.30am EST.

Since publication of the Stage 1 Draft Report, the Commission has been made aware of additional ex ante trades that are not represented in Figure 5.2. Due to the way STTM trading rights are utilised by some participants, the unaccounted for trades appear to AEMO's system as being within-participant.[229] One stakeholder has suggested that these types of trades are occurring at the Sydney and Adelaide STTM hubs by large users, however, we have been unable to quantify the number as the data are not available.[230]

Figure 5.2 Majority of transactions on the STTM are within-participant



Source: AEMO. Within-participant trades is the quantity of gas transacted between the same entity; ex ante trades is the quantity of gas traded between different entities at the start of the gas day; ex post deviation trades is deviations during the gas day.

While Figure 5.2 may underestimate the number of ex ante trades to a degree, the majority of transactions occurring on the STTM are still likely to be within-participant. This suggests that the level of trading liquidity[231] is likely to be low across the STTM hubs most of the time. Our understanding from discussions with participants, however, is that there can be adequate depth to support the purchasing activities of some industrial users on any given day, thereby providing these participants with an alternative supply option to contracting with producers or retailers.[232]

In terms of the future development of the STTM hubs, growth in overall trading activity may be naturally limited due to their physical locations at the end of long

229 AEMO requires shippers to hold trading rights with sufficient pipeline capacity for the quantities of gas they are scheduled to flow. Trading rights directly reflect shippers' underlying contractual arrangements with pipeline operators. If trading rights are traded between shippers, then AEMO's system may not be able to accurately measure all ex ante trades.

230 CQ Partners, Stage 1 Draft Report submission, p. 3.

231 Liquidity in this context is defined as the ability to buy or sell gas without causing a major change in price and without incurring significant transaction costs.

232 Informal discussions with STTM participants indicates that purchasing not insignificant gas volumes on the STTM will move the price, but the increase generally results in a total price paid that is still less than prices offered under alternative arrangements.

transmission pipelines. This restricts the ability of participants to purchase STTM gas and ship it to other markets due to the cost of transport and/or the predominant flow of pipelines. It also indicates that these markets are unlikely to develop into liquid commodity trading hubs, which are characterised by the ability to move gas easily in or out of the hub area and a large number of different types of gas users.

Accordingly, there is uncertainty around whether the ex ante price will develop into a robust and credible reference price that participants can price contracts off and trade large volumes of gas around. The ex ante price is generally considered to reflect short term imbalances between daily gas requirements and long term contract positions, as discussed in section 5.2.2. However, we note that the original STTM design was probably not developed for the purpose of establishing a reference price, where the focus was on facilitating transparent and competitive short term trading of imbalances.

5.2 Key issues in the STTM

A number of reviews have been carried out over the past 24 months, and have identified potential issues with the STTM design. These include the:

- ESAA assessment of the east coast gas market that was prepared by Deloitte in May 2013;[233]
- AEMC's Scoping Study that was published in July 2013;[234] and
- Australian Government's Department of Industry and the Bureau of Resource and Energy Economics (BREE)'s Eastern Australian Domestic Gas Market Study, which was published in January 2014.[235]

AEMO has also completed two reviews since the commencement of the market as part of its obligations under the NGR. The first review related to the operation of the market, including MOS, settlement surplus and shortfall, and deviation and variation parameters, and was published on 30 March 2012.[236] This review led to AEMO submitting a number of rule changes to the Commission around MOS, deviations and settlement surplus and shortfall.

The second review considered the merits of transitioning the market to intraday trading and looked at the appropriateness of the market price cap and cumulative price threshold. This review was published on 21 December 2012 with AEMO recommending not to progress intraday trading or additional hubs at that time.[237]

233 See: http://www.esaa.com.au/policy/east_coast_gas_market_reform_1_1

234 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Gas-market-scoping-study

235 See: http://www.industry.gov.au/Energy/EnergyMarkets/GasMarketDevelopment/Pages/EasternAustralianDomesticGasMarketStudy.aspx

236 AEMO, *STTM Operational Review and Demand Hubs Review*, Final Report, 30 March 2012.

237 AEMO, *STTM Intraday Review*, Final Report, 21 December 2012.

Since commencement of the STTM in September 2010, AEMO has submitted 11 rule changes to the Commission for consideration. These are summarised in Appendix E.3. While the NGL allows any interested party to submit a rule change proposal relating to the STTM, to date industry has progressed proposed changes through AEMO's consultative forums.[238]

Matters considered in this chapter

The following sections of this chapter set out the key issues that have been identified in the STTM, drawing on observations from previous reviews, submissions to this process and analysis by the Commission. The issues are presented in three categories:

1. STTM complexity and the value of the ex ante price signal (considered in section 5.2.1).
2. Inability to manage risk (considered in section 5.2.2).
3. Transaction costs associated with value adding market functions (considered in section 5.2.3).

5.2.1 STTM complexity and the value of the ex ante price signal

This section outlines the complexities associated with operating in the STTM, including for parties operating across the STTM and DWGM, and the value provided by the ex ante price signal.

Complexities associated with the STTM

As discussed above, the STTM was designed to facilitate commodity trading and a competitive on-the-day balancing service between transmission and distribution pipelines. The complexities associated with a market designed to provide both of these functions may be one of the reasons behind the high per GJ transaction costs associated with operating in and administering the market, relative to the volume of trades that benefit directly from the market arrangements.

We note that complex energy market designs may, depending on the objectives of the market, be unavoidable. Electricity and natural gas are commodities that both exhibit unique physical characteristics that influence the means of exchange. However, the level of complexity and resultant costs should be minimised, while the value a centralised market provides to its participants should be greater than its costs.

Some of the complexities inherent in the design of the STTM manifest in the number of potential price risks that participants could be exposed to. These include:

- ex ante price;
- pipeline capacity payment and charge;

238 NGL, section 295(1).

- deviation payment and charge - calculated based on either the ex ante price, ex post price, MOS increase or decrease price, or the high or low contingency gas price;
- variation payment and charge - calculated based on a sliding scale on a quantity and percentage basis;
- contingency gas price; and
- settlement surplus and shortfall.

While the ex ante price is determined the day before the gas day, the other price risks are generally a function of what occurs during the gas day. A detailed overview of the on-the-day balancing mechanism is set out in Appendix E, with further analysis of risk management in the STTM outlined below in section 5.2.2.

In addition, differences between the STTM and DWGM may be acting as a barrier for firms looking to enter both markets; or contributing to additional costs for participants who currently operate in both of these markets. As the STTM and DWGM are both primarily used by shippers for balancing and incremental commodity trades, there is likely to be value in considering measures to harmonise aspects of the market designs.

Some of the key differences between the STTM and DWGM include:

- market terminology;
- start time for gas trading days (6.00am in the DWGM, 6.30am in the Sydney and Adelaide STTM hubs and 8.00am in the Brisbane STTM hub);
- trading periods (DWGM has five intra-day trading periods, while the STTM operates on a day-ahead basis with market schedule variations for intraday renominations);
- market price caps and cumulative price thresholds (market price cap is $800/GJ in the DWGM and $400/GJ in the STTM); and
- separate prudential requirements.

Value of STTM ex ante price signal

As discussed above, the current STTM design requires that all gas shipped to and/or withdrawn from the hub is transacted through the market. Since the majority of trades are appear to be within-participant, the level of liquidity underpinning the market price in the STTM can be considered to be low. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times.

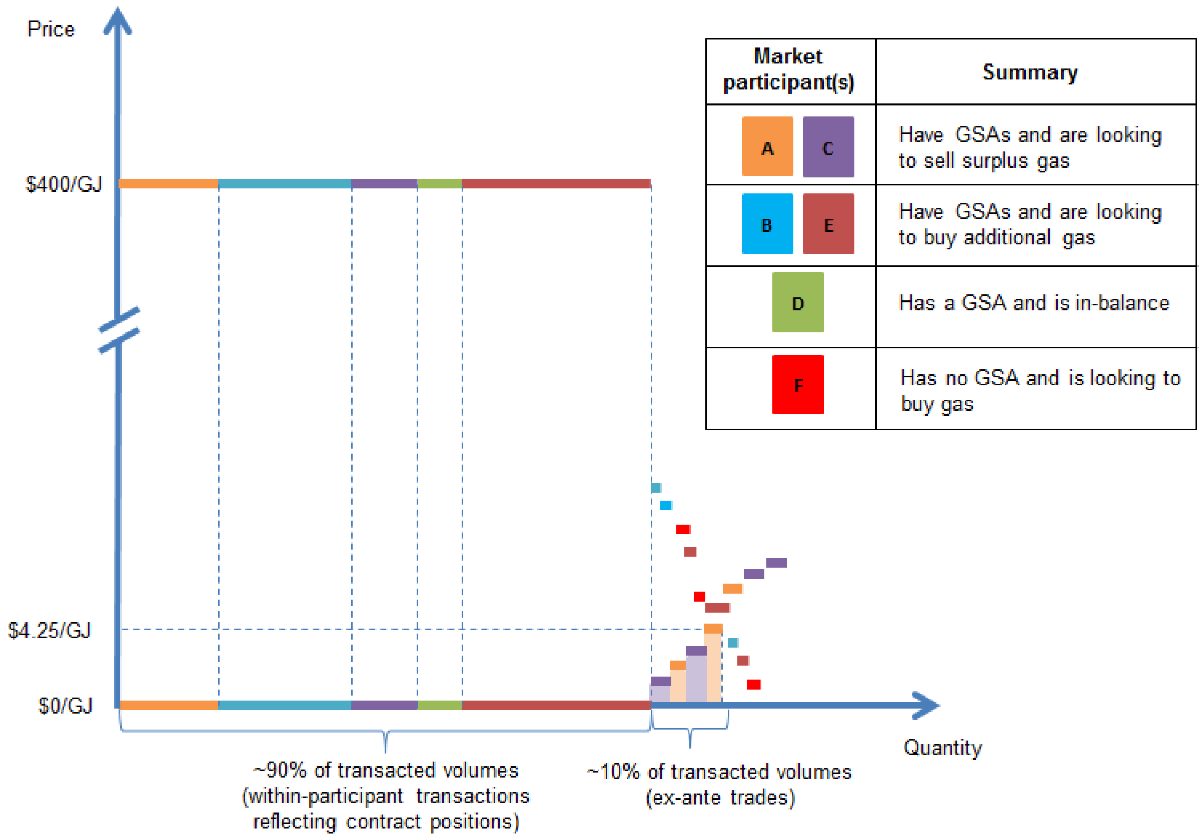
Figure 5.3 presents a stylised example of the supply and demand conditions inherent in the ex ante STTM price signal and how they contribute to an overall low level of liquidity in the market. Each coloured segment of the curves represents a particular bid or offer price and volume pair by a market participant (there are six assumed market participants, each represented by a different colour).

Price is represented on the vertical axis, while volume is represented on the horizontal axis (the length of each coloured segment denotes how much volume a participant is willing to buy or sell to the market at that price). The overall positions of each market participant are summarised in the box next to the figure.

The quantities of gas participants require to meet contractual obligations (the flat sections of the supply and demand curves) can be thought of as representing absolute illiquidity since market participants require these volumes to fulfil their contractual obligations (they are price inelastic).

Consequently, we would expect market participants to submit bids and offers for these volumes that ensure they are scheduled (these bids and offers are assumed to be $400/GJ (the market price cap) and $0/GJ, respectively, in the example below). The remaining bids and offers are essentially those that set the market price in the STTM.

Figure 5.3 Stylised example of the supply and demand conditions inherent in the ex ante STTM price signal



Source: AEMC analysis.

Since most participants endeavour to align their bids and offers so as to not be exposed to the STTM ex ante price risk (as the green participant in Figure 5.3 has done), the remaining bids and offers reflect daily imbalances between participants' requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to between five and 10 per cent of total volumes based on data available to the AEMC.

Consequently, the observed STTM market price is likely to be susceptible to both a small volume of trades and a small number of market participants.

Stakeholder submissions to the Discussion Paper

Most submissions to the Discussion Paper raised the complexity of operating in the STTM (and DWGM) as an issue. In order to summarise stakeholders' views we have separated the issues into four categories:

1. Complexity of the markets.
2. Consistency between market parameters.
3. Future development of the facilitated markets.
4. The value of the STTM ex ante price signals.

Complexity of the markets

The Major Energy Users (MEU) suggest that the use of the facilitated markets for purchasing gas on a short term basis is "very limited due to the complexity of the gas markets and the very high adjustments made ex post".[239] Similarly, Origin Energy agrees that the STTM and DWGM are complex to operate in and a key principle for this review should be to simplify the unnecessarily complex elements of the markets.[240]

GDFSAE considers the existence of multiple hub designs creates complexity and inefficiencies that are likely to discourage greater participation outside of retailers in major demand centres. It notes that the STTM and DWGM require more development to manage challenges facing the market to facilitate the optimal level of trade outside of bilateral contracts.

GDFSAE considers that the development of these markets has not progressed due to the complicated nature of the hubs, which require significant work to progress even minor operational matters, and the consultative forums chaired by AEMO, which are unable to regularly unify behind individual reforms.[241]

QGC states that multiple market designs make trading complex, inefficient and costly for participants and that, due to the specific design features and the size of the markets, STTM prices do not always impact the underlying supply and demand for gas.[242]

239 MEU, Discussion Paper Submission, p. 4-6.

240 Origin, Discussion Paper submission, p. 2.

241 GDFSAE, Discussion Paper submission, pp. 8-9.

242 QGC, Discussion Paper submission, p. 6.

The Group of Leading Energy Companies and Major Users (GLECMU) considers that resolving identified issues with existing trading hubs is a necessary pre-condition to the development of an integrated gas market. They note that multiple market designs make trading complex and inefficient for participants, with each market characterised by "specific and enduring limitations". Further, hubs should be designed to facilitate maximum participation and promote liquidity.[243]

While the APGA considers the STTM hubs provide a liquid balancing mechanism and still remain relevant to the Energy Council's Vision, they consider there is an important question around whether they are overly costly and complex for this role. APGA suggests there is a question around the STTM's ongoing role given the advent of multiple supply hubs and capacity trading.[244]

APA considers that, while the STTM hubs have provided an effective and competitive gas balancing service, there appears little evidence of the STTM hubs increasing the number of retailers due to significant exposures that can result from the market. APA notes that the STTM is unnecessarily complex for the primary gas balancing function that they perform and this drives significant market costs.[245]

The Australian Petroleum, Production and Exploration Association (APPEA) argues that the differences between each of the facilitated markets require participants who operate in each of the markets to have different information technology, administrative and compliance systems in place. APPEA notes that these add costs and can be a barrier to entry.[246]

Consistency between market parameters

APGA considers that aligning the market parameters, such as gas day timing and market price caps across the facilitated markets will improve efficiencies, reduce complexity and increase opportunities for trade across the market.[247]

Alinta suggests that issues currently worthy of consideration are: greater alignment of market parameters, in particular the significant differences in market price caps; establishing a common gas day to enhance coordination of trading; and aligning prudential requirements across the gas and potentially electricity markets.[248]

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243 Industry statement, Discussion Paper submission, p. 3. Note: the Industry Statement was supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association.

244 APGA, Discussion Paper Submission, p. 32.

245 APA, Discussion Paper submission, p. 9.

246 APPEA, Discussion Paper submission, p. 3.

247 APGA, Discussion Paper submission, p. 13.

248 Alinta Energy, Discussion Paper submission, p. 5.

QGC points out that harmonising the gas day across states and consistency of trading periods and settlement processes would make it easier to trade gas across the east coast.[249]

Origin sees limited benefit in a work program to harmonise the gas markets under one single design, with the costs likely to outweigh any benefits. However, harmonising parameters, such as gas day start times, prudential requirements and market price cap and cumulative price threshold should be explored. Origin also suggests there may be merit in the way AEMO presents data for each market to promote consistency and reduce complexity and cost, for instance:

- Definition of terms in each facilitated market.
- Consistency in reports provided by AEMO.
- Timeliness of data provided by AEMO.
- Standardised gas market format for how data is provided and received.

The ESAA argues that to improve trading and liquidity, reducing transaction costs and minimising pricing risks is essential. The ESAA also suggests that investigating options to harmonise the STTM and DWGM would be a positive initiative and this could include the creation of a single gas day (noting there are currently three), consolidation of prudential requirements and harmonisation of market parameters.[250]

Lumo Energy argues that while the STTM hubs clearly add value through flexibility in managing gas portfolios, they can be improved by harmonising the start of the gas day across the STTM and DWGM, which Lumo considers would reduce barriers to entry.[251]

Future development of the facilitated markets

AGL suggests a review aimed at simplifying the rules and services provided by AEMO for the STTM hubs and notes this could take the form of dispensing with the pricing functionality in the STTM hubs, while maintaining incentives for balancing. AGL notes there may be other ways to reduce complexity and help lower the significant costs of participating in and administering the STTM.[252]

EnergyAustralia argues that the current market arrangements are not appropriate to meet the challenges of the future. Specifically, there are three fundamentally different types of facilitated markets for trading gas that are complex and were designed independently of the others. EnergyAustralia points out that deviations and imbalances are managed in a different manner between the STTM and DWGM, which

249 QGC, Discussion Paper submission, p. 6.

250 ESAA, Discussion Paper submission, p. 4.

251 Lumo Energy, Discussion Paper Submission, pp. 6-7..

252 AGL, Discussion Paper submission, p. 2.

increases complexity and costs. As such, market development needs to focus on improvements targeted to individual markets, but guided by a coherent strategy.[253]

Adelaide Brighton notes that the STTM and Wallumbilla GSH provide large industrial consumers greater access to wholesale markets in addition to the standard gas contract model. These markets provide industrial customers with price transparency and liquidity that can assist in reducing the average price of gas.[254]

However, Adelaide Brighton considers that, given the three different facilitated market designs, there would be efficiency gains from a uniform regulatory framework. They note that the DWGM could function as an STTM hub, allowing for gas purchases and sales within Victoria to be consistent with STTM in Adelaide and Sydney.[255] A key improvement to the STTM would be to allow the full settlement of market schedule variations through the STTM settlement system.

Qenos supports the full settlement of MSVs through the STTM settlement system to negate the need for individual parties to put in place separate documentation with other market participants for MSV transactions. Qenos would prefer this to the introduction of intra-day trading, which is likely to increase the level of resources required to participate in the STTM.[256]

Santos argues that the complexity of multiple different market rules, mechanisms, timings and administration requirements mean that new entrants require significant time to gather the expertise to effectively manage the risk of using multiple markets. Santos recommends the AEMC consider standardising all balancing markets so there is one model across all regions to reduce complexity for participants.[257]

Alinta Energy supports the AEMC investigating the benefits potentially associated with consolidating the facilitated markets into a single Australian gas market, while acknowledging the extent of this task.[258]

Stanwell sets out a long term vision for the gas market based on the design of the NEM where AEMO would play a prominent role in scheduling flows and determining prices based on injection and withdrawal bids. Under this model, all pipeline investment would be regulated by the AER and buyers would pay usage charges based on consumption. A balancing market would be operated by AEMO, with the cost of operating the service recovered from consumers.[259]

APA considers the STTM design could be simplified to become solely a gas balancing market. This could take the form of AEMO preparing monthly MOS allocations

253 EnergyAustralia, Discussion Paper submission, p. 3.

254 Adelaide Brighton Cement Limited, Discussion Paper submission, p. 2.

255 ibid.

256 Qenos, Discussion Paper submission, p. 2.

257 Santos, Discussion Paper submission, p. 3.

258 Alinta Energy, Discussion Paper submission, p. 5.

259 Stanwell, Discussion Paper submission, p. 1-2.

through a competitive tender process, with deviations allocated by the pipeline operator to shippers on a daily basis. APA considers this design would reduce costs and remove market risk created by setting an ex ante price, while resolving the counteracting MOS issues. It would also concentrate liquidity at supply hubs, which have greater potential to develop into deep and liquid trading locations.

APA argues that this change to the scope of the STTM could be applied to Brisbane in the first instance due to its close proximity to Wallumbilla.[260] While noting that the current market structure is meeting the needs of participants, APA has put forward a future vision that includes establishing gas supply hubs at natural trading points, such as Moomba and in Victoria, and simplified market-based balancing at demand centres.

With respect to the Brisbane STTM, Origin argues that the success of the Wallumbilla GSH "suggest there is a strong impetus to cease operations of the Brisbane STTM". Origin considers the balancing function performed by this market could be undertaken at Wallumbilla and has undertaken preliminary work around how this could occur.[261]

In discussing the impact of counteracting MOS in the STTM, and in particular in Adelaide, the AER notes that actions of those outside the hub, such as gas-fired generators, can potentially lead to counteracting MOS. The AER considers it worth exploring whether the current geographical limitations of the Adelaide STTM hub are appropriate, including whether gas-fired generation should be excluded.[262]

Lumo Energy argues that while the STTM hubs clearly add value through flexibility in managing gas portfolios, they can be improved through reviewing the MOS arrangements in the STTM.[263]

Value of STTM ex ante price signals

APGA notes that the STTM is not a true commodity supply price, rather it is the price of imbalance on the day and "it is the lack of demand for balancing services that drives a low price, not a surplus of commodity". APGA suggests that participants who do not use the service provided by the STTM are subsidising those that do.[264]

APA considers that the prices published in the STTM are not credible references, as the bulk of trades on the market are between related entities.[265]

Qenos has recently become a market participant in the Sydney STTM hub and sees the STTM as a potential alternative means of purchasing gas. Qenos notes that the STTM has facilitated communication, negotiation and increased commercial gas transacting between gas suppliers and customers. However, Qenos suggests that the STTM prices

260 APA, Discussion Paper submission, p. 10.

261 Origin, Discussion Paper submission, p. 4

262 AER, Discussion Paper submission, p. 3.

263 Lumo Energy, Discussion Paper submission, p. 3.

264 APGA, Discussion Paper submission, pp. 29-30.

265 APA, Discussion Paper submission, p. 9.

are not an accurate reflection of contracted gas prices because the STTM is primarily a balancing market.[266]

5.2.2 Inability to manage risk

Participants can face price risk in the STTM through the ex ante commodity market and the on-the-day balancing market. These aspects are discussed below.

Ex ante price risk

With relatively stable gas supply and demand conditions in the east coast market historically, participants have generally traded gas on the STTM within the confines of their bilateral contracts, with the contracts acting as a natural hedge against price risk. For example, a large industrial user with a GSA will effectively be selling and buying the gas to itself at whatever the price is in the STTM and, thus, will be perfectly hedged from the ex ante price.

Price risks emerge when participants use the ex ante commodity market to sell or purchase gas outside of their contractual positions. For example, a retailer who has expected demand at a hub of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ and bid to withdraw 100 TJ in the ex ante market. In this case, the retailer will be exposed to ex ante price risk on 20 TJ, which is the volume of gas not supplied under a long term contract.

As can be seen in Figure 5.4, the Adelaide STTM has experienced periods of high ex ante price volatility in between more moderate market outcomes.[267] Compared to one of the most liquid gas trading hubs internationally - the Henry Hub in North America - volatility is understandably higher in the Adelaide STTM due to the smaller number of participants and volumes of gas traded. Although, we note that the number of high priced days is low and the market price cap has never been reached in any of the STTM hubs.[268]

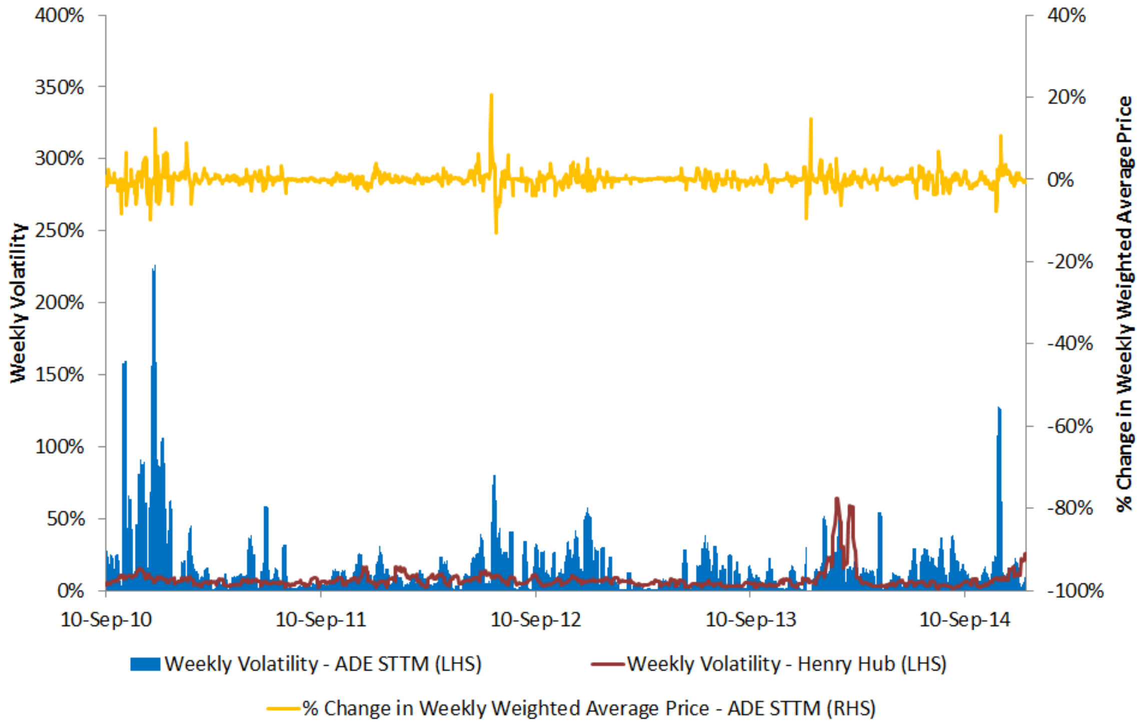
Average volatility since market start across the STTM hubs has been highest in Brisbane, followed by Sydney, while Adelaide has exhibited the least ex ante price volatility, on average. Exchange-based financial derivative products are not currently available to hedge ex ante price risk in the STTM; although we understand bespoke over-the-counter risk management products, such as contracts-for-difference, are being used by some participants.

266 Qenos, Discussion Paper submission, p. 4.

267 Adelaide was selected out of the three markets because it was found to be the least volatile of the hubs operating on the east coast.

268 High priced days are defined as the ex ante price being over 150% of the average price.

Figure 5.4 Adelaide STTM ex ante price has exhibited periods of high volatility



Source: AEMC volatility analysis based on price and volume data sourced from AEMO (for the STTM) and price data sourced from the EIA (for the Henry Hub). STTM daily and weekly average prices were calculated by weighting ex ante prices by volumes. Weekly volatility was calculated using the methodology set out in: EIA, *An Analysis of Price Volatility in Natural Gas Markets*, August 2007.

Note: Volatility is driven by percent differences in prices of gas between days across a rolling week. Large price movements at higher prices may equate to a comparable level of volatility as a smaller price movement when natural gas prices are lower. Further, increasing natural gas prices do not necessarily indicate whether a market is volatile, since volatility is defined by the degree of price variation in the market, not by the level of prices or direction of price movements. See: EIA, *An Analysis of Price Volatility in Natural Gas Markets*, August 2007, p. 1.

On-the-day balancing price risk

The other form of price risk in the STTM is through the on-the-day balancing mechanism if a participant deviates from its ex ante schedules.

As the STTM has been designed to incorporate a balancing function, features of the market consistent with this service impose what have been described by participants as unhedgeable risks. These include variation payments and charges related to the use of MSVs, as well as deviation payments and charges, which are imposed when participants deviate from ex ante schedules and do not submit market schedule variations.

A detailed overview of the STTM's on-the-day balancing mechanism design, and the calculation of payments and charges, is set out in Appendix E.

Observations from previous reviews

As part of the Scoping Study, stakeholders raised the following concerns with the STTM relating to risk:[269]

- An inability to hedge against all of the risks associated with operating in this market because there is not a single daily price that reflects all of the costs payable by participants.
- The level of the MOS price cap, which some claimed was too high; the prevalence of counteracting MOS in the Adelaide market; the potential for the MOS arrangements to be gamed; and the inability of participants to offer MOS on a daily basis.
- The lack of visibility to participants around their exposure to deviation charges.

Deloitte noted as part of the ESAA's assessment of the east coast gas market that the STTM (and DWGM) has been a critical factor in enabling new entry by allowing participants without long term gas and transport agreements to gain initial access to retail markets before entering contracts. However, it was noted that GSAs and GTAs remain the primary approach to managing risk once participants have entered the market.[270]

However, participants interviewed by Deloitte suggested that the STTM has had little impact on transparency, as gas prices reflect only the long or short positions of participants and not the underlying GSA prices.[271]

Stakeholder submissions to the Discussion Paper

Risk management and price transparency was a key theme reflected in submissions. Origin Energy highlights the following elements related to the STTM that may impede participants' ability to manage risk:[272]

- MOS service payments and commodity payments.
- Short and long deviations payments.
- Contingency gas.
- Settlement surplus and shortfall.

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269 K Lowe Consulting, *Gas Market Scoping Study,* A report for the AEMC, July 2013, p. 96.

270 ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform* , May 2013, p. 53.

271 ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform* , May 2013, p. 60.

272 Origin Energy, Discussion Paper submission, pp. 2-3.

Origin "strongly supports improving the current arrangements so that each gas day is self-contained and participants are then able to manage risk on a single day without reference to other days". Origin notes that such an approach would require the MOS pricing arrangements to be re-evaluated so participants face the full economic value of deviations, which could occur by implementing a marginal clearing price approach.[273]

The remaining submissions under risk management and price transparency are separated into the following categories:

- Intra-day trading.
- Value of STTM price signals.
- Development of financial derivatives

Intra-day trading

Stanwell supports the introduction of intra-day trading to reduce imbalance charges, although they note that some users may not have access to their gas consumption data on an intra-day basis. Stanwell also argues that balancing services in the STTM may be more effective if shippers were able to offer MOS on a day-ahead basis, rather than a month-ahead. Alternatively, Stanwell raises the possibility that balancing is performed by the pipeline at a rate fixed by the AER.[274]

Lumo Energy argues that while the STTM clearly adds value through flexibility in managing gas portfolios, they can be improved through intra-day trading, which would provide market participants with the additional flexibility to manage portfolios over the course of a day. Lumo argues that the additional cost and complexity of intra-day trading would be outweighed by the benefits of being able to better manage deviations.[275]

Development of financial derivatives

The Plastics and Chemicals Industries Association (PACIA) supports the development of financial derivatives as another means for risk management, although notes that this will need a daily price to settle against. Simplifying the STTM registration process to encourage more participants and incorporating market schedule variation trading in the STTM is also supported.[276]

Qenos argues that while purchasing gas on the STTM can be cheaper than under bilateral contracts, the price risks are substantial for users that have limited demand response. This means that users such as Qenos still require long term gas supply contracts to manage this risk. In this context, Qenos would be interested in the AEMC

273 Origin Energy, Discussion Paper submission, p. 3.

274 Stanwell, Discussion Paper submission, p. 5.

275 Lumo Energy, Discussion Paper submission, pp. 6-7

276 Plastic and Chemicals Industries Association, Discussion Paper submission, p. 7.

exploring additional tools to manage STTM risk, such as financial derivatives that would enable short to medium term hedges.[277]

Santos notes that because trading in the facilitated markets is confined to "overs and unders" it is not always suitable for large industrial customers to manage their full commodity risk and for derivative contracts to be established. However, Santos argues the main impediment is the lack of firm transport capacity to get gas to and from the different trading markets.[278]

GDFSAE considers that within-day price signals, trading day definitions, consistency of trading periods and settlement processes should be set to facilitate trade and support a more liquid market, including the development of forward products. Areas for investigation suggested by GDFSAE range from a rationalised market design, coordinated dispatch, use of understandable within day charges, better use of balancing and maximising trade, signalling the value of capacity and services inside hubs and consolidation of prudential regimes.[279]

5.2.3 Transaction costs associated with the value adding market functions

Costs incurred by AEMO in its role as operator of the STTM are recovered from participants by charging a fee for gas transacted through the hubs. Since participation in the markets is mandatory for parties wishing to ship gas to the hub and/or withdraw gas, this fee reflects an unavoidable transaction cost for these parties.

The STTM fee is currently $0.082/GJ and in 2014-15 AEMO has reported that it expects STTM expenditure to be $10.8 million. Around 40 per cent of AEMO's expenditure relates to labour costs, while 30 per cent is depreciation and amortisation.[280]

AEMO's fees for operating the STTM are higher on an inflation-adjusted basis than was expected when costs were estimated for the GMLG in 2006.[281] Consultants MMA estimated the ongoing costs for an Adelaide and Sydney STTM to be around $1.6 million annually, which equates to around $1.87 million in 2015.[282]

On this basis, STTM operating costs in 2014-15 are over five times those estimated by MMA in 2006, although AEMO’s current fees include the operating costs for the Brisbane STTM, which were not included in the 2006 estimate.[283] However, we note that there appear to be large fixed costs associated with operating the STTM hubs. This is because AEMO's 2011-12 fees, which excluded the Brisbane STTM, were $10 million -

277 Qenos, Discussion Paper submission, p. 5.

278 Santos, Discussion Paper submission, p. 3.

279 GDFSAE, Discussion Paper submission, p. 10.

280 AEMO, *Consolidated Draft Budget and Fees: 2014-15*, Published May 2014, p. 15.

281 An average annual inflation rate of 2.5 per cent is assumed.

282 Gas Market Leaders Group 2006, *National Gas Market Development Plan,* Gas Market Leaders Group report to the Ministerial Council on Energy, Canberra, p. 38-39.

283 We note that if depreciation and amortisation are excluded from the 2014-15 fees, STTM operating costs are still around 50 per cent higher than expected when the market was designed.

marginally less than the 2013-14 fees of $10.1 million, which was the first full financial year the Brisbane STTM had been operating.[284]

If the annual cost of operating the STTM is only recovered from gas that is traded for the purposes of settling ex ante commodity trades and ex-post deviation trades, the per GJ AEMO fee rises from approximately $0.08/GJ to approximately $0.89/GJ across the STTM hubs.[285] This indicative cost is relatively high in the context of gas prices typically observed in the STTM hubs of $3.8-4.3/GJ (20-23 per cent).[286] It also does not include the costs associated with the time and resources individual firms must dedicate to operating in the STTM.

The current structure for recovering AEMO's costs of operating the STTM has, arguably, resulted in those trading mostly in balance (where injections equal withdrawals) being charged a disproportionate amount, relative to those who rely more on the ex ante commodity and balancing functions. This is evident in the difference between AEMO's market fee and the indicative market fee that would be levied if the costs of the market were only recovered from the trades facilitated by the STTM, as can be seen in Table 5.1.

Table 5.1 AEMO $/GJ STTM fees would be significantly higher if levied only on ex ante commodity and ex post deviation trades

	2011-12	2012-13	2013-14
Total STTM costs ($m)	11.3	10.7	10.6
Total withdrawals (PJ)	139	164	166
Ex ante commodity and ex post deviation trades (PJ)	11	10.5	11.9
Actual AEMO fee ($/GJ)	0.07	0.07	0.08
Implied AEMO fee ($/GJ) – based on ex ante commodity and ex post deviation trades	1.03	1.02	0.89

Source: AEMC analysis using AEMO supplied expenditure and gas trade data.

Note: 'Total STTM costs' include both AEMO expenditure and MOS allocation service costs.

However, in presenting this analysis, which is based on the best data available to the AEMC at the time of conducting this review, we note three important caveats:

284 AEMO, *STTM final budget and fees 2013-14*, p. 8. Note that the $10.6 million 'total STTM costs' for 2013-14 shown in Table 5.1 below is the sum of 'AEMO expenditure' ($10.1 million) and 'MOS allocation service costs' ($0.5 million).

285 These cost increases have been calculated by the AEMC using AEMO supplied expenditure and gas trade data between 2010-11 and 2013-14.

286 Average STTM prices are based on volume weighted quarterly prices published by the AER.

1. **Completeness of underlying data:** As discussed in section 5.1, since publication of the draft report the Commission has been made aware of additional trades between different entities that have occurred but, because of the way STTM trading rights are being utilised by some participants, the unaccounted for trades appear to AEMO's system as being between the same entities.

   While the Commission is aware through anecdotal evidence that this type of trading is occurring at the Adelaide and Sydney hubs, we are unable to quantify the extent of trade. The analysis above should therefore be considered as an order of magnitude assessment of the transaction costs associated with the market. We note that we have not received any evidence to suggest that the same use of trading rights is facilitating additional ex ante trading at the Brisbane hub above what is represented in Figure 5.2.

2. **Need for another form of balancing mechanism:** In the absence of the STTM, another form of balancing mechanism would need to be implemented to manage "unders and overs". Therefore, while this analysis has considered the absolute costs of the STTM on participants, it has not looked at the avoided costs, which would need to consider the costs of an alternative balancing mechanism.

3. **Lowering barriers to entry and increasing competition:** Direct costs of the STTMs may be outweighed by the additional flexibility provided to new entrant retailers and large industrial users of gas, who could choose to purchase some or all of their gas requirements through the market instead of directly from producers or retailers. This optionality could lower barriers to entry and promote competition in relevant downstream markets, such as gas retailing, creating benefits for consumers.

   While these effects are difficult to measure, submissions to the Stage 1 Draft Report, as well as the Commission’s discussions with large users, indicate that industrial users are beginning to use the STTM more regularly to manage their gas supply needs. Conversely, retailer interviews conducted as part of the AEMC's 2014 Retail Competition Review found that "the risks in the STTM are such that new entrant retailers have tended not to rely on this option, preferring instead to enter into gas supply and transportation contracts".[287]

Observations from previous reviews

As part of the ESAA's assessment of the east coast gas market, Deloitte estimated that transaction costs in the STTM were approximately $1 per GJ traded. The review suggested that these high costs appear to be driven by the low volume of gas traded between participants. Deloitte also noted that the significant differences between the

287 KLC & FSC 2014, *AEMC 2014 Retail Competition Review: Retailer Interviews*, Report for the AEMC, p. 42.

STTM and DWGM designs can increase costs for participants operating across jurisdictions.[288]

Stakeholders in the Scoping Study expressed mixed views on the STTM, with some participants noting that it provides a useful way to manage imbalances and has enhanced price transparency, while others noted that little trade was actually undertaken through the STTM and that prices were not particularly informative. Some stakeholders also noted there was little evidence to suggest new entrants could rely solely on the STTM to procure gas.[289]

The Eastern Australian Domestic Gas Market Study noted that the STTM was designed to complement long term gas contracts and provide an option for making up short run supply and demand shortfalls. The report identified that the STTMs currently trade insignificant gas volumes and may have only a limited relevance to the price of the long term gas contracts.[290]

Stakeholder submissions to the Discussion Paper

Most submissions to the Discussion Paper comment on the high transaction costs associated with the STTM, with general consensus that this was an issue the AEMC should explore further in the review.

Stanwell argues that the STTM hubs impose significant costs on participants, pointing out that nearly half of AEMO's annual budget for operating the STTM, or $4.9 million, is labour costs, which "seems to be very high given market operations should be highly automated".[291] Stanwell is also of the view that there is no evidence participants are relying on the STTM solely for their gas supply - rather it is primarily used for managing "unders and overs".[292]

AGL notes that the facilitated markets are essentially balancing arrangements in downstream distribution networks and suggests that "the markets are characterised by complexity and resultant overhead costs which culminate in a service cost per GJ, particularly in the STTM, which overwhelm any value to be had from trading in the market".[293]

Arrow Energy notes that although it does not participate in the STTM (and nor does it have any intention to enter this market in the future), it has been made aware of the significant costs and administrative burden attached to the STTM.[294]

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288 ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform*, May 2013, p. 62-63; also referenced in ESAA, Discussion Paper submission, p. 4.

289 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, p. 96.

290 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 64.

291 Stanwell, Discussion Paper submission, p. 4.

292 ibid.

293 AGL, Discussion Paper submission, p. 1.

294 Arrow Energy, Discussion Paper submission, p. 8.

5.3 AEMC's Stage 1 findings and recommendations

This section summarises submissions received on the draft report and sets out the Commission's findings from this stage of the review, as well as outlining the direction for Stage 2.

Stage 1 recommendations are also provided as required under the Commission's terms of reference and represent "no regrets" changes where implementation could begin immediately, irrespective of the future development of the STTM and its role in the broader east coast gas market framework.

5.3.1 Submissions to the Stage 1 Draft Report

The draft report recommended that consideration be given during Stage 2 of the review as to whether the original objectives of the STTM remained relevant and, if so, whether the market was meeting those objectives. A recommendation to harmonise gas day start times across the spot markets on the east coast was also proposed.

The following section discusses the views raised on each of these in submissions to the Stage 1 Draft Report.

Stakeholder views on the direction for Stage 2 of the review

A number of market participants were supportive of the AEMC's draft position to establish a technical working group to consider whether the STTMs, particularly the Brisbane hub, could be simplified and transaction costs for participants reduced.[295] However, while participants generally supported the view to reducing complexity and costs, others noted it was premature to conclude that the STTM should only perform balancing functions, as the ex ante commodity function and compulsory nature of the markets were also important features, especially for large industrial users and mid tier retailers.[296]

A number of submissions put forward that the costs of operating in the STTMs were too high for a largely automated market. These parties consider that a review of the current costs incurred by AEMO in operating the STTM should be implemented to identify ways to increase efficiency.[297] CQ Partners questioned whether the STTM costs were inflated due to cross-subsidisation between the STTM and the Wallumbilla

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295 MEU, Stage 1 Draft Report submission, p. 2; AGL, Stage 1 Draft Report submission, p. 3; EUAA, Stage 1 Draft Report submission, p. 3; Origin, Stage 1 Draft Report submission, p. 3; Visy, Stage 1 Draft Report submission, pp. 2-5.

296 MEU, Stage 1 Draft Report submission, p. 2; Orora, Stage 1 Draft Report submission, p. 3; EnergyAustralia, Stage 1 Draft Report submission, pp. 5-6; SA Water, Stage 1 Draft Report submission, p. 2; Visy, Stage 1 Draft Report submission, pp. 2-5; GDFSAE, Stage 1 Draft Report submission, pp. 5-6.

297 Stanwell, Stage 1 Draft Report submission, p. 2; CQ Partners, Stage 1 Draft Report submission, pp. 2-4; Australian Paper, Stage 1 Draft Report submission, p. 3; Visy, Stage 1 Draft Report submission, pp. 2-5; Qenos, Stage 1 Draft Report submission, p. 3.

GSH, noting there was no transparency from AEMO around whether the GSH is operating at a significant loss due to the small number of trades being executed.[298]

A key theme through submissions was stakeholders looking for the AEMC to establish a pathway for the development of the facilitated markets on the east coast. Most participants consider it is an opportune time to develop a long term strategy that holistically considers the number and location of facilitated markets, including the appropriate objectives for the markets going forward.[299] AGL put forward that, while it is interested in further analysis of trading locations as part of this work, it may be more productive to resolve issues with the STTM (primarily costs of participation) and Wallumbilla GSH (low trading liquidity) before using limited resources to create more hubs based on models that have not yet delivered their predicted value.[300]

Stanwell and Hydro Tasmania both made the point that the AEMC should consider long term visionary changes to the market instead of continuing to support the piecemeal development to date, and that a clear long term strategy is required.[301]

Lastly, submissions received from some large users and representatives of large users suggest that the AEMC has already decided on a market structure for the east coast and/or favoured a model for the STTM.[302] The AEMC notes that this is not the case and the intention is to use Stage 2 of this review (in conjunction with the DWGM review) to assess the current east coast market structure and make recommendations to the Energy Council around the future development of the STTM, DWGM, GSH and other aspects of the market.

Stakeholder views on harmonising the gas day start time

The majority of submissions consider that gas days should be aligned for all facilitated markets on the east coast. No submissions were opposed to the alignment.

APA notes that there would be system, administrative and legal costs for APA, but does not consider that this should be considered a material barrier to enacting a standard gas day, if corresponding benefits from such a change can be identified.[303] Santos notes that, from its perspective, there would be minimal costs in changing start times.[304]

298 CQ Partners, Stage 1 Draft Report submission, p. 6.

299 Origin, Stage 1 Draft Report submission, p. 5; APA, Stage 1 Draft Report submission, p. 17; Alinta Energy, Stage 1 Draft Report submission, p. 3; ESAA, Stage 1 Draft Report submission, p. 5; AEMO, Stage 1 Draft Report submission, p. 4; Santos, Stage 1 Draft Report submission, p. 4.

300 AGL, Stage 1 Draft Report submission, p. 4

301 Stanwell, Stage 1 Draft Report submission, p. 1; Hydro Tasmania, Stage 1 Draft Report submission, p. 2 & 4.

302 Major Energy Users, Stage 1 Draft Report submission, p. 3; CQ Partners, Stage 1 Draft Report submission, p. 6; and Qenos, Stage 1 Draft Report submission, p. 2.

303 APA, Stage 1 Draft Report submission, p. 2.

304 Santos, Stage 1 Draft Report submission, p. 4.

A number of parties suggested specific times for the start of a harmonised gas day on the east coast, including:

- AGL considers that the gas day should begin at 12.00am as it would coincide with the lowest level of activity across the gas day;[305]

- Santos and EnergyAustralia both consider that 6.00am would be an appropriate start time;[306]

- QGC noted that an 8.00am commencement would be reasonable as the majority of east coast gas market volumes already flow on pipes supplying markets with this start time;[307] and

- APA considers that the standard time should be between 6.00am and 10.00am, given the important system support and other information requirements related to the end of gas day.[308]

Origin considers the recommendation to harmonise gas day start times should outline a process to initiate this work, which would include canvassing the range of system and contractual changes required and their associated costs, rather than a definitive recommendation to move to a particular start time for the gas day.[309] The ESAA also considers that it would be more prudent for the Stage 1 report to recommend initiating a process to examine this issue in detail, rather than trying to settle on a particular gas day start time.[310]

Visy also supports aligning gas day start times and notes that the particular start time is not of importance per se but should be determined based on minimising change and disruption when considering all east coast markets together.[311] Stanwell noted that it seems reasonable to start the gas day based on the minimum cost of change and considers this is likely to occur where the minimum number of meters needs to be changed.[312] EnergyAustralia notes that harmonising gas day start times is not urgent and can be considered as part the package to harmonise other key settings across the DWGM and STTMs.[313]

AEMO considers it important to consider the entire gas supply chain, not just facilitated markets, when considering the harmonisation of gas day start times.[314] Visy

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305 AGL, Stage 1 Draft Report submission, p. 3.

306 Santos, Stage 1 Draft Report submission, p. 3; EnergyAustralia, Stage 1 Draft Report submission, p. 3.

307 QGC, Stage 1 Draft Report submission, p. 2.

308 APA, Stage 1 Draft Report submission, p. 14.

309 Origin, Stage 1 Draft Report submission, p. 3.

310 ESAA, Stage 1 Draft Report submission, pp. 4-5.

311 Visy, Stage 1 Draft Report submission, p. 7.

312 Stanwell, Stage 1 Draft Report submission, p. 6.

313 EnergyAustralia, Stage 1 Draft Report submission, p. 3.

314 AEMO, Stage 1 Draft Report submission, p. 5.

also notes that a mechanism needs to be in place to require gas sellers to accommodate new market times which do not strictly align with gas day start times reflected in current legacy gas supply contracts.[315]

In addition, GDFSAE, Origin and QGC all support further consideration of harmonisation with the electricity market (ie 4.00am).[316] APA on the other hand does not see that there is a strong case for aligning the gas day to the electricity market, and considers that a 4.00am start would considerably increase costs for the market without a clear benefit.[317] Santos also considers that there is little relevance in aligning the facilitated markets with the NEM, noting that these are completely separate markets in fuel origination, structure, settlement and delivery.[318]

5.3.2 Final Stage 1 findings

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. Some participants have also found the STTM useful as a way of initially entering the gas market before committing to bilateral gas supply and transportation agreements.

Feedback from some stakeholders 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. 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 also represents an added level of complexity for entities wishing to operate across jurisdictions, as it is characterised by a different set of arrangements, including gas day start times, to the DWGM in Victoria, although the roles of each market are similar.

Conversely, some stakeholders have argued that the STTMs are a low cost market with no significant barriers to entry for customers. Large industrial users have, in particular, put forward a view that the STTMs provide a competitive alternative supply source to producers and major retailers, and that some cost is justifiable in order to have a properly functioning market. While most large users support the STTM, there is some consensus among this group that the markets could be run more efficiently and potentially simplified and/or harmonised with the DWGM.

315 Visy, Stage 1 Draft Report submission, p. 7.

316 GDFSAE, Stage 1 Draft Report submission, p. 5; Origin, Stage 1 Draft Report submission, p. 3; QGC, Stage 1 Draft Report submission, p. 2.

317 APA, Stage 1 Draft Report submission, p. 14.

318 Santos, Stage 1 Draft Report submission, p. 4.

Growth in trading activity at STTM hubs may 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 experience 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.

5.3.3 Final Stage 1 recommendation

As part of Stage 1 of the East Coast Review, the AEMC is required to give consideration to whether there are any existing issues that can be resolved with the intention of enhancing the ability of the STTM to achieve the NGO, irrespective of what future shape the facilitated market arrangements may take (the outcome of Stage 2).

The Commission considers that harmonising the three spot market gas day start times across the DWGM, STTM and GSH would reduce compliance costs and barriers to trading across multiple hubs, and is therefore likely to promote the NGO. The Commission recommends the Energy Council propose a rule change request to change the STTM gas day start times to 6.00am and to define the GSH gas day start time in the NGR as 6.00am, in line with the arrangements for the DWGM.

Harmonisation of gas day start times

Facilitated market gas days currently start at three different times across the east coast:[319]

- 6.00am for the DWGM in Victoria.
- 6.30am for the Sydney and Adelaide STTM hubs.
- 8.00am for the Brisbane STTM hub and Wallumbilla GSH.

With the continued integration of the east coast gas market and an increasing number of participants trading across more than one facilitated market, the Commission considers that harmonising gas day start times is likely to promote the NGO by lowering compliance costs and decreasing the complexity for participants trading, or who may wish to trade, across multiple hubs.

A common gas day start time is expected to minimise compliance costs by reducing the need for businesses that are required to utilise the STTMs and DWGM from having to develop separate internal processes for managing different gas day start times. Greater consistency will also mean that participants can better align their bids and offers across

319 The gas day start times are prescribed in the NGR for both the STTM and the DWGM. The gas day start time for products offered on the Wallumbilla GSH is specified in the exchange agreement developed by AEMO.

all of the hubs on any given day, reducing complexity (which can act as a barrier to entry) and promoting the continued integration of gas supply on the east coast.

Over time, consistency in gas day start times across the five (and potentially six) facilitated gas markets on the east coast should promote the supply of natural gas at lowest possible cost, which is in the long term interests of consumers.

As noted above, some parties have highlighted a number of one-off costs associated with implementing this change. However, it is also generally considered that these costs are likely to be less than the long term benefits of a single gas day start time regime as the integration of the east coast market continues, although sufficient lead time will be required to implement system changes, including:

- re-setting and modification of coding for each field flow computer; and
- commercial and legal processes to amend contracts.

Implementation of harmonising the gas day start time

While the majority of submissions considered that gas days should be aligned for all facilitated markets on the east coast, only a few submitted a specific start time and there was no real consensus among those that did. We understand from AEMO that the current 6.00am start time for the DWGM means that the first reschedule of the day (ie 10.00am) occurs after the typical mid-morning peak and so minimises uncertainty for participants.

Given the identified benefits of moving to a single gas day start time regime on the east coast, the Commission recommends the Energy Council submit a rule change request to the AEMC that:

- changes the gas day start time for the STTM hubs to 6.00am, in line with the current arrangements for the DWGM;[320] and
- defines the gas day start time for the GSH in the NGR as 6.00am.

While the Commission is recommending that a gas day start time of 6.00am is proposed for the purpose of the rule change request, it is acknowledged that more detailed consideration of the benefits and costs of specific start time options needs to be undertaken, and that the appropriate process for this to occur is through a rule change. The rule change process will allow the Commission and stakeholders to engage at a more granular level on the operational, commercial and legal work that will need to be carried out to implement the recommendation.

Further detail on the recommendation to define the gas day start time for the GSH in the NGR is set out in section 7.3.3.

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320 Rule 201 and 366 of the NGR currently specify that all date and time references for both the DWGM and STTM are specified in Australian eastern standard time (and are not adjusted for daylight saving time in any jurisdiction).

The AEMC will work closely with AEMO as part of the rule change and exchange agreement processes to ensure implementation of this recommendation minimises disruption to industry.

5.3.4 Stage 2 direction

Taking into account feedback from stakeholders, and given the changes underway in the east coast market, the Commission considers it is an opportune time for reflection on the role of the STTM (and DWGM and GSH) in the broader east coast gas market, including setting out a development plan for the market into future.

In particular, the AEMC considers there is merit in considering the following issues as part of Stage 2 of the review:

1. whether the originally stated STTM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and

2. if not, whether the objectives and design of the STTM need to be re-focussed, taking into account developments in the broader east coast market and the STTM's role alongside other facilitated markets.

Stage 2 of the review will involve consultation with stakeholders around the type and number of facilitated markets on the east coast and how best to develop the markets such that they meet their objectives and the needs of participants efficiently. This will include investigating the scope for increasing the consistency in gas market designs across the east coast to minimise complexity and transaction costs, where practicable.

To commence this work, we intend to publish a Discussion Paper for consultation in early August 2015 that will outline the characteristics of different gas market designs and potential structures that could be implemented to meet the Energy Council's Vision. A technical working group will also be established to provide the Commission with advice as it finalises its recommended approach for the Stage 2 Draft Report in December 2015.

Through this process we will work closely with AEMO as it progresses its work to further develop the design of the Wallumbilla GSH. We will consider the interaction between the STTM and commodity trading at current and potential GSH locations, and will also consider broader questions, such as whether trade should be at specific physical locations or at "virtual" points encompassing parts or all of the pipeline network. Finally, we will also consider implementation and transitional issues, such as whether there would be merit in trialling a simplified market design at Brisbane.

The timing of the Discussion Paper, technical working group and the ultimate Stage 2 Draft Report is illustrated in Figure 5.5 below, alongside the outputs for the coincident DWGM Review over this period.

Figure 5.5 Timeline for inputs to the Stage 2 Draft Report

6 Declared Wholesale Gas Market

Box 6.1 Summary of findings and recommendations

When the DWGM was implemented the STTM and GSH had yet to be established and there were no large-scale LNG developments on the horizon in Queensland. The Victorian system operated in isolation and was not physically connected to the rest of the east coast pipeline transmission system.

Today, the DWGM is generally regarded as providing an effective and competitive balancing service that facilitates the trading of gas in Victoria. Victoria has relatively high levels of retail competition in gas compared to other jurisdictions, in-part due to the presence of the DWGM. Nonetheless, and as with the STTM hubs, only a small portion of total gas "traded" arguably benefits from the centralised market arrangements.

Complexities associated with the DWGM design may impose disproportionate operational and administrative costs on participants. Additionally, the material differences between the DWGM and STTM represent an added level of complexity for firms wishing to operate across jurisdictions, even though the practical roles of these markets are similar.

Similar to the STTM, the AEMC considers it an opportune time to consider:

- whether the originally stated DWGM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and
- if not, whether the objectives and design of the DWGM need to be re-focussed, taking into account developments in the broader east coast market and the DWGM role alongside other facilitated markets.

The Commission will progress these issues as part of the DWGM Review, which, while a standalone review, will have its analysis integrated with this review, and vice versa. This is likely to involve consultation with stakeholders around the type and number of facilitated markets on the east coast and how best to develop the markets such that they meet their objectives and the needs of participants.

With respect to recommendations that can be implemented more immediately, the AEMC recommends that the Energy Council develop changes to the NGL to remove the limitation on who can submit a rule change request relating to the DWGM.

As noted in Chapter 5, the AEMC also recommends the Energy Council submit a rule change request to set gas day start times to 6.00am, in line with the DWGM.

6.1 Market overview

This section provides an overview and background to aspects of the DWGM relevant to the issues considered throughout this review. It covers the original objectives for establishing the DWGM, key design features as well as how the market operates in practice. We have also included a detailed appendix on how the DWGM operates in practice (see Appendix F).

Market objectives

The DWGM was established by the Victorian Government in March 1999 and the objectives for doing so were as follows:[321]

- To support full retail competition – the market carriage model and the DWGM were seen as a way of encouraging new entry by retailers because they would not need to enter into long-term GTAs and they would have equivalent access as incumbent shippers to a mechanism to trade imbalances and purchase gas at the spot price.
- To encourage diversity and security of supply and upstream competition – the transparency of pricing provided by the DWGM and the operation of the market carriage model were expected to encourage the development of new sources of supply and upstream competition.

In addition, the DWGM and market carriage arrangements in Victoria were developed to reflect the physical characteristics of the DTS. In particular:

- the DTS was essentially not connected to the rest of the east coast at that stage (eg the Eastern Gas Pipeline, the SEA Gas Pipeline and the Tasmanian Gas Pipeline had not been built) with supply effectively coming from one supply source (ie Longford);
- the DTS was, and still is, a physically highly meshed network that, at the time, had a large amount of spare capacity;
- the amount of gas that can be stored in the DTS was relatively small and cannot be relied upon to manage significant deviations between demand and contracted supply (LNG storage plays an important role in managing peak day demand);[322] and

321 K Lowe Consulting, *Gas Market Scoping Study,* A report for the AEMC, July 2013, p. 11; and VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, pp. 21-24.

322 A 2002 report by VENCorp states that total linepack in the DTS varies between about 450 TJ and 600 TJ over each day as the system demand is satisfied and that on peak days over 1,100 TJ is shipped through the network, or approximately twice the entire linepack in the system. By way of comparison, the then peak demand on the Moomba to Sydney pipeline was stated to be approximately 25 per cent of the daily transported volume. See: VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 23.

- the demand profile was, and still is, largely characterised as exhibiting a significant degree of seasonal and daily variability (as a result of high residential heating load).

These physical characteristics mean that the DTS must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained. The physical characteristics also meant that it was considered to be very difficult to determine how to define firm capacity rights to shippers (ie as opposed to the rest of the east coast that operate more on a 'point-to-point' basis).[323]

Market design

In February 2007, the DWGM moved from the original market design based on daily ex post price determination to one where prices were determined on an ex ante intra-day basis. This shift was the result of a review conducted by VENCorp during 2003-04 that found the then existing ex post design did not provide participants with either the ability or the incentive (ie the price signal) to respond to changing market conditions during the day.[324] In particular, at the time it was thought that ex post price signals would not serve the needs of gas-powered electricity generators (expected at the time to have an increasing presence in the generation sector going forward) and these participants needed the ability to re-nominate their bids and offers.

Market operation

It is generally the view of market participants that the DWGM has been working well since market-start, encouraging retail competition in Victoria and providing market participants with an effective mechanism to trade imbalances. Evidencing this is the range of physical gas market participants, such as retailers, gas-fired generators and large industrial customers, that now use the DWGM (the number and type of participants currently registered at each hub is set out in Table F.2). In addition, a number of participants appear to use the DWGM as means of initially entering the gas market, before committing to a bilateral gas supply and gas transportation agreement.

Similar to the STTM hubs, the majority of gas transacted through the DWGM is by participants who are selling gas into the market and at the same time buying it back. This is because, while the DWGM is compulsory, most participants have underlying gas supply agreements in place and do not need to use the DWGM to trade with different entities.

Figure 6.1 categorises DWGM transactions between 2010-11 and 2013-14 into three types based on data provided by AEMO: within-participant trades, ex ante trades and ex post deviation trades. The figure shows that around 80 per cent of total transactions in the DWGM are within-participant trades.[325] It shows that the majority of gas

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323 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 11.

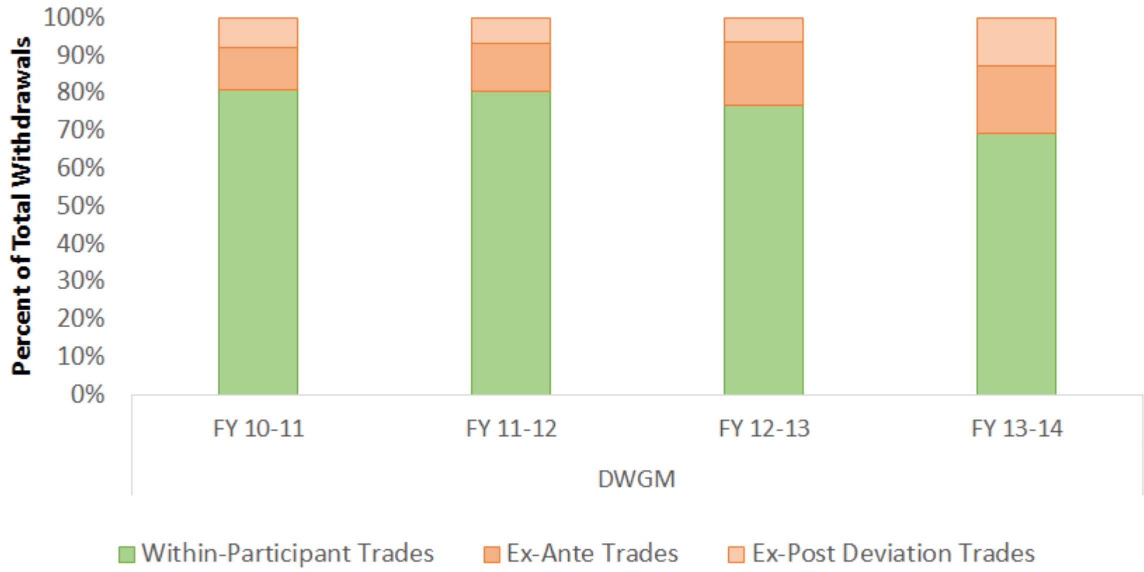
324 VENCorp, *Victorian Gas Market Pricing and Balancing Review,* Recommendations to Government, 30 June 2004.

325 The actual percentages are 81 per cent for 2010-11 and 2011-12, 77 per cent for 2012-13 and 69 per cent for 2013-14.

transacted through the DWGM has been between the same entities, with a small proportion traded through ex ante and as ex post deviation trades.

As noted in Chapter 5, since publication of the draft report the Commission has been made aware of additional trades between different entities that have occurred but, because of the way STTM trading rights are being utilised by some participants, the unaccounted for trades appear to AEMO's system as being between the same entities.[326] While similar issues have not been raised by any party for the DWGM trading data to date, the Commission considers it prudent to consider that the data provided by AEMO only allows for an order of magnitude assessment.

Figure 6.1 Majority of trades on the DWGM are within-participant



Source: AEMO. Within-participant trades is the quantity of gas transacted between the same entity; ex ante trades is the quantity of gas traded between different entities before each schedule; ex post deviation trades is deviations during schedules.

Based on the data available to the AEMC, it appears that, as the majority of trades that occur on the DWGM are within-participant, the level of trading liquidity between different entities is also likely to be relatively low most of the time.[327] Consequently, there is uncertainty around whether the ex ante price is likely to develop into a robust and credible reference price that market participants can price contracts off and trade large volumes of gas around.

The ex ante DWGM price is generally considered to reflect imbalances between daily gas requirements and long-term contract positions, as discussed in section 6.2.2. However, we note that it is not clear whether producing a robust pricing point was the

326 AEMO requires shippers in the STTM to hold trading rights with sufficient pipeline capacity for the quantities of gas they are scheduled to flow. Trading rights directly reflect shippers' underlying contractual arrangements with pipeline operators. If trading rights are traded between shippers, then AEMO's system may not be able to accurately measure all ex ante trades.

327 Liquidity in this context is defined in Chapter 5.1 as the ability to buy or sell gas without causing a major change in price and without incurring significant transaction costs.

intention of the original market design, where the focus was on facilitating short term trading of imbalances and establishing a level of price transparency.

6.2 Key issues in the DWGM

A number of reviews have been carried out over the last 24 months identifying potential issues with the DWGM design. These include the:

- ESAA's assessment of the east coast gas market, prepared by Deloitte in May 2013;[328]
- AEMC's Scoping Study, published in July 2013;[329]
- Victorian Gas Market Taskforce, competed in October 2013;[330] and
- Australian Government's Department of Industry and BREE's Eastern Australian Domestic Gas Market Study, published in January 2014.[331]

Section 295(3) of the NGL currently provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[332] Since commencement of the DWGM in 1999, AEMO has submitted six rule changes to the AEMC for consideration since it took over responsibility for rule changes from VENCorp in 2009. These are summarised in Table F.1.

Matters considered in this chapter

The following sections of this chapter set out the key issues that have been identified in the DWGM, drawing on observations from previous reviews, submissions to this process and analysis by the AEMC. The issues are presented in three categories:

- DWGM complexity and the value of the ex ante price signal (considered in section 6.2.1).
- Inability to manage risk (considered in section 6.2.2).
- Transaction costs associated with value adding market functions (considered in section 6.2.3).

These three issues are synonymous with those identified in Chapter 5 for the STTM. This is a result of the two markets providing the same fundamental services (a

328 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013.

329 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013.

330 Victorian Government, *Gas Market Taskforce*, Supplementary Report, October 2013.

331 Department of Industry (Australian Government) *Eastern Australian Domestic Gas Market Study*, January 2014.

332 Victoria is currently the only adoptive jurisdiction.

balancing trading service and a spot commodity trading service),[333] even though the two detailed market designs differ markedly. The analysis in this section is therefore similar to that in Chapter 5 for the STTM hubs but presented again to maintain autonomous chapters.

6.2.1 DWGM complexity and the value of the ex ante price signal

This section outlines the complexities associated with operating in the DWGM, including for parties operating across the DWGM and the STTM, and the value provided by the ex ante price signal.

Complexities associated with the DWGM

The DWGM is a set of market arrangements designed to offer a balancing trading service, a spot commodity trading service and to allocate capacity on the DTS. The complexities associated with a market designed to provide all of these functions may be one of the reasons behind the relatively high per GJ transaction costs associated with operating in and administering the market, relative to the volume of trades that benefit directly from the imposition of the market (as outlined in section 6.2.3).

Complex energy market designs may, depending on the objectives of the market, be unavoidable. Electricity and natural gas are commodities that both exhibit unique physical characteristics that influence the means of exchange. However, the level of complexity and resultant costs should be minimised, while the value a centralised market provides to its participants should be greater than its costs.

Some of the complexities inherent in the design of the DWGM are manifested in the number of potential price risks that participants could be exposed to. These include:

- the ex ante price;
- three types of complex uplift charges participants may face (congestion uplift, surprise uplift and common uplift);[334] and
- deviation payments.

While the ex ante price is determined before each schedule, the other price risks are generally a function of what occurs during the gas day. A detailed overview of these design aspects is set out in Appendix F, with further analysis of risk management in the DWGM outlined below in section 6.2.2.

In addition to being complex relative to the primary role the DWGM currently plays in the east coast gas market, differences between the DWGM and STTM may be acting as a barrier for firms looking to enter both markets; or contributing to additional costs for

333 In contrast to the STTM, the DWGM is also used to allocate the capacity of the DTS amongst market participants via the scheduling process. The allocation of pipeline capacity is done outside of the market in the STTM (via bilateral contracts).

334 Uplift charges are further discussed in Appendix F.

participants who currently operate in both of these markets. As the DWGM and STTM are both used primarily for balancing and incremental ex ante commodity trades, there is likely to be value in considering measures to harmonise aspects of the market designs.

Some of the key differences between the STTM and DWGM include:

- market terminology;
- start time for gas trading days (6.00am in the DWGM, 6.30am in the Sydney and Adelaide STTM hubs and 8.00am in the Brisbane STTM hub);
- trading periods (DWGM has five intra-day trading periods, while the STTM operates on a day-ahead basis);
- market price caps ($800/GJ in the DWGM and $400/GJ in the STTM hubs); and
- separate prudential requirements.

In the Scoping Study, stakeholders noted that the resources required to become acquainted with operating in Victoria may be deterring producers and large users from participating or deterring those shippers that just want to export gas from Victoria.[335]

Value of the DWGM ex ante price signal

As discussed above, the current DWGM market design requires that all gas withdrawn from the DTS is to be transacted through the market. Since the majority of transactions that occur on the DWGM are considered to be within-participant, the level of liquidity underpinning the market price in the DWGM can be considered low. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times.

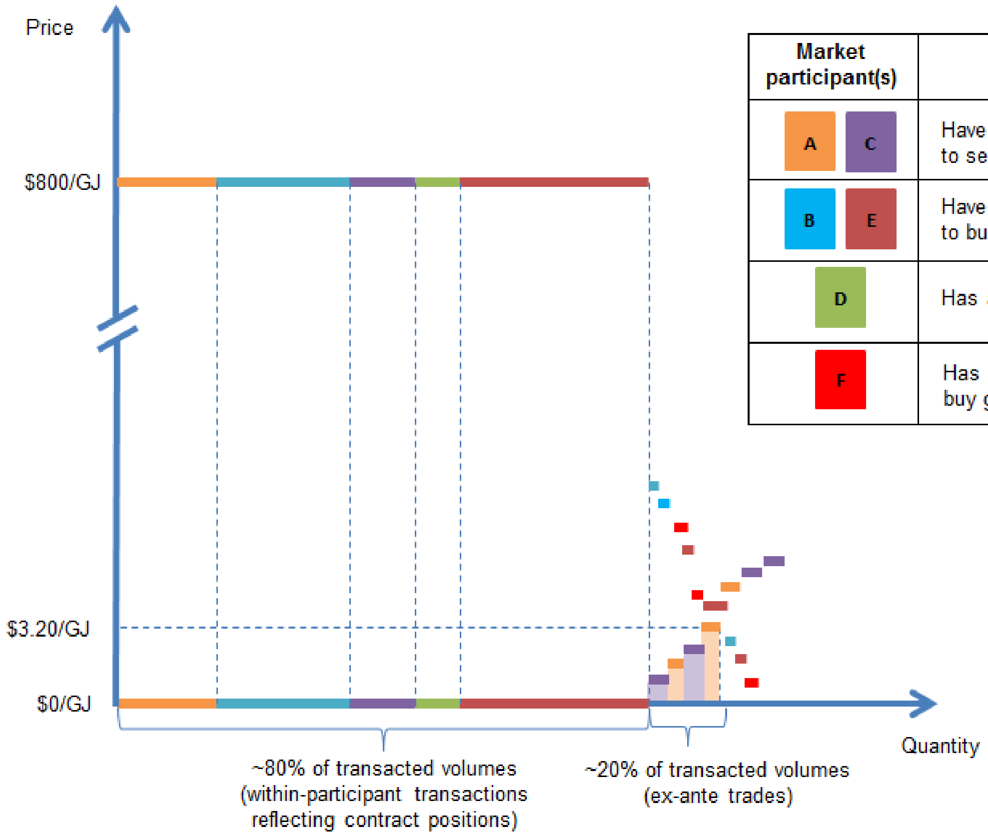
Figure 6.2 presents a stylised example of the supply and demand conditions inherent in the ex ante DWGM price signal and how they contribute to an overall low level of liquidity in the market. Each coloured segment of the curves represents a particular bid or offer price and volume pair by a market participant (there are six assumed market participants, each represented by a different colour). Price is represented on the vertical axis, while volume is represented on the horizontal axis (the length of each coloured segment denotes how much volume a participant is willing to buy or sell to the market at that price). The overall positions of each market participant are summarised in the box next to the figure.

The quantities of gas that participants require to meet contractual obligations (the flat sections of the supply and demand curves) can be thought of as representing absolute illiquidity since market participants require these volumes of gas to fulfil their contract obligations (these volumes are highly price inelastic). As such, we would expect market participants to submit bids and offers for these volumes that ensure they are

335 K Lowe Consulting, *Gas Market Scoping Study,* A report for the AEMC, July 2013, p. 91.

scheduled (these bids and offers are assumed to be $800/GJ (the market price cap) and $0/GJ, respectively, in the example below). The remaining bids and offers are essentially those that set the market price in the DWGM.

Figure 6.2 Stylised example of the supply and demand conditions inherent in the ex ante DWGM price signal



Market participant(s)	Summary
A C	Have GSAs and are looking to sell surplus gas
B E	Have GSAs and are looking to buy additional gas
D	Has a GSA and is in-balance
F	Has no GSA and is looking to buy gas

Source: AEMC analysis.

Since most participants endeavour to align their bids and offers so as to not be exposed to the DWGM ex ante price risk (as the green participant 'D' in Figure 6.2 has done), the remaining bids and offers reflect daily imbalances between participants' requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to approximately 20 per cent of total volumes based on data available to the AEMC, as noted above.[336]

Consequently, the observed DWGM ex ante market price is likely to be susceptible to both a small volume of trades and a small number of market participants.

Observations from previous reviews

Concerns were raised by a number of stakeholders in the Scoping Study about the complexities and costs associated with operating in the DWGM and the potential for

336 As can be seen from Figure 6.1 this 20 per cent also includes ex post deviations, which have been excluded from this stylised example for ease of exposition.

these to act as a barrier to entry into the market. Stakeholders suggested the following improvements to the DWGM as part of this study:[337]

- Simplifying unnecessarily complex elements of the DWGM.
- Harmonising certain elements of the DWGM (such as the start of gas day and market price caps) across all facilitated markets to reduce the risk of arbitrage across the markets and the costs faced by participants operating in these markets.
- Pool prudential requirements across the DWGM and STTM and allow subsidiaries to pool prudential requirements.

The Scoping Study also found that the complexities associated with operating in the DWGM (and the market carriage arrangements applying to the DTS) represents an additional complexity for those shippers that just want to export gas from Victoria.[338]

There was a general perception across all stakeholders consulted with as part of ESAA's assessment of the east coast gas market that the facilitated markets (and associated interventions such as the Gas Bulletin Board and GSOO) impose significant costs on participants. Shippers noted that key costs for trading participants include registration and activity fees, and the need for enhanced IT systems and, in general, it was noted that the costs for interacting with the facilitated markets had grown over time.[339]

Stakeholder submissions to the Discussion Paper

The complexity of the DWGM (and the STTM hubs) was raised in almost all submissions. In order to summarise stakeholders' views, we have separated the issues into four categories:

1. Complexity of the markets.
2. Consistency between market parameters.
3. Future development of the DWGM (and wider east coast).
4. The value of DWGM ex ante price signals.

Complexity of the markets

In its submission Origin Energy suggested a key principle to guide this review process should be to simplify the unnecessarily complex elements of the facilitated markets.[340]

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337 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, pp. 95-97.

338 K Lowe Consulting, *Gas Market Scoping Study,* A report for the AEMC, July 2013, p. 91.

339 ESAA *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, p. 62.

340 Origin, Discussion Paper submission, p. 2.

MEU said that using the 'spot' function of the DWGM is very limited due to the complexity of market and the various adjustments made ex post (ie uplift charges).[341]

Santos noted that the complexity of multiple facilitated market rules, mechanisms, timings and administration requirements, mean that any new entrant would require significant time to gather the required expertise to effectively manage the risk of using a, or multiple, facilitated market(s).[342]

APPEA notes that each of the three forms of facilitated market currently in operation on the east coast (ie the STTM hubs, the Wallumbilla GSH and the DWGM) is different and that these differences require participants who operate in each of these markets to have different information technology, administrative and compliance systems in place to participate in each of these markets. APPEA notes that these differences add costs for participants and can be a barrier to entry into these markets, particularly for smaller entities.[343]

AGL raised the issue of intra-day trading on the DWGM. AGL noted that, with the shift towards gas as a major generation fuel in Victoria not eventuating, the DWGM is characterised by a complex mechanism that is over-engineered for what it does. Noting this however, AGL stated that the absence of appreciable linepack and the peakiness of gas demand in Victoria sit well with the ability to revise bids and offers during the course of a gas day.[344]

Arrow Energy states that Australian gas markets are currently disparate, even though physically connected, creating inefficiencies or hurdles to transacting and that achieving supply across the complex arrangements is often not practical or adds significant cost and risk. Arrow Energy states that harmonising elements of existing markets (such as the start of gas day and market price caps) to reduce the risk of arbitrage across the markets, and the costs faced by participants operating in both markets, would reduce complexity and facilitate increased participation.[345] The views of other parties on the harmonising of these market parameters is outlined below.

Consistency between market parameters

Origin recommends aligning gas day start times, as well as potentially market price caps.[346] Santos also noted that aligning these two parameters had been raised in the earlier AEMC gas market scoping study and noted that it agrees that they should be aligned.[347]

341 Major Energy Users, Discussion Paper submission, p. 4.

342 Santos, Discussion Paper submission, pp. 6-7.

343 APPEA, Discussion Paper submission, p. 3.

344 AGL, Discussion Paper submission, p. 5.

345 Arrow Energy, Discussion Paper submission, p. 7.

346 Origin, Discussion Paper submission, p. 4.

347 Santos, Discussion Paper submission, p. 3

QGC noted that there is a lack of harmonisation across the facilitated markets of key features including trading day definition, consistency of trading periods and settlement processes and, as a starting point, suggested that harmonising the gas day across the states (and potentially aligning to the timing of the electricity market) would make it easier to trade gas across the east coast.[348]

APGA noted an immediate action should be to align the market parameters across the facilitated markets.[349] Alinta also suggested harmonising market parameters and gas days.[350] GDFSAE expressed the view that market definitions, trading days, trading periods and settings and parameters should be rationalised.[351]

The GLECMU noted that within day price signals, trading day definitions, consistency of trading periods, and settlement processes should be set so as to facilitate trade and support a more liquid market including encouraging the development of forward products.[352]

ESAA considers that differences between the DWGM and STTM hubs can potentially increase costs for participants operating across these markets and that opportunities to deliver greater consistency between these markets is a positive initiative. The ESAA considers there is merit in examining:[353]

- a single gas day;
- consolidating prudential requirements (with consideration also given to the Wallumbilla gas supply hub and NEM); and
- harmonisation of gas market parameters.

The ESAA considers that the extent to which each of these increase costs for market participants is unclear and that any examination of these issues should therefore include a broad assessment of materiality as well as considering the extent to which any proposed change is appropriate in the context of each market.[354]

GDFSAE and Alinta both support consolidating prudential arrangements across the facilitated markets.[355] Origin also recommended expanding prudential requirements from the STTM and DWGM to the GSH and the NEM.[356]

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348 QGC, Discussion Paper submission, p. 6.

349 APGA, Discussion Paper submission, pp. 12 & 27

350 Alinta, Discussion Paper submission, p. 5.

351 GDFSAE, Discussion Paper submission, p. 9.

352 Industry Statement, Discussion Paper submission, p. 3. Note: the Industry Statement was supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association.

353 ESAA, Discussion Paper submission, p. 4.

354 ibid.

355 GDFSAE, Discussion Paper submission, p. 10; and Alinta, Discussion Paper submission, p. 5.

Future development of the DWGM (and wider east coast)

Mixed views were raised in submissions as to the future of the DWGM as well as the wider east coast market. ABCL suggested that there are some efficiency gains to be extracted from a uniform regulatory framework on the east coast, allowing a common mechanism for the setting of spot prices. To this end, ABCL recommend that the DWGM be operated as a 'Melbourne STTM hub' to ensure consistency with Sydney and Adelaide.[357]

Stanwell also supports the integration of the east coast gas markets, provided the benefits can be shown to outweigh the costs.[358]

Origin Energy, on the other hand, thinks there is limited value in a large scale overhaul of the gas markets to harmonise them under one single design (eg a STTM) and noted that such an exercise would be extremely costly and unlikely to deliver a commensurate level of benefit. Origin states that overseas examples such as Europe show that markets can be integrated effectively without requiring a single market model across those markets.[359] Similarly, AGL states its considered view is that the DWGM is generally best left alone as the costs of dismantling the existing arrangements and installing new rules and market systems are unlikely to result in net benefits.[360]

While noting that the current market structure is meeting the needs of participants, APA put forward a future vision that includes establishing gas supply hubs at natural trading points and simplified market-based balancing at demand centres. This could include transitioning the DWGM to a gas supply hub model supported by contract carriage pipelines and creating a separate balancing market for Victoria.[361] APA does not see this as urgent, more a vision for the long-term development of the market.

GDFSAE suggests adopting a coordinated dispatch across the east coast. GDFSAE provides the example of a market participant injecting at Moomba and states that they should be able to nominate Sydney and Adelaide and achieve the price that best matches the value of the commodity and transportation costs.[362]

GDFSAE also states that signalling the value of capacity and services inside hubs does not presently occur and, ideally, the market would signal the value of solutions as they become known whether those solutions are pipeline, facility or storage orientated. GDFSAE goes on to state that the DWGM does not currently provide useful signals and encourages participants to push in significant amounts of gas to resolve a variety of issues and avoid charges.

356 Origin, Discussion Paper submission, p. 4.

357 Adelaide Brighton Cement, Discussion Paper submission, p. 2.

358 Stanwell, Discussion Paper submission, p. 1.

359 Origin, Discussion Paper submission, p. 4.

360 AGL, Discussion Paper submission, p. 5.

361 APA, Discussion Paper submission, p. 29.

362 GDFSAE, Discussion Paper submission, p. 9.

GDFSAE proposes that the use of multiple nodes, with capacity signals between those nodes, may be worth considering and notes that the impact of having a series of nodes, in effect mini-hubs inside the Victorian network, should enable the market to signal for efficient responses. GDFSAE states that, conceptually, each hub on the east coast currently operates like a node; therefore the use of multiple nodes in Victoria is not an inconsistent approach to that applied currently.[363]

Value of DWGM ex ante price signals

APGA, APA and the MEU all noted that the observed prices in the DWGM do not represent a commodity price (or long-term value of gas) but rather an imbalance (or short-term constraint) price.[364] QGC stated that, due to the operation of specific design features and the size of the markets, it is questionable as to whether the published prices in the DWGM and STTM hubs always reflect the underlying supply and demand for gas, or whether they are impacted by other factors.[365]

GDFSAE noted the potential to develop a gross index of prices that reflects all trades within a hub, whether under bilateral contract or not.[366] ERM Power is of the view that the market price cap in the DWGM is excessive and should be reviewed because it exposes retailers to undue risk. ERM Power has suggested that the price cap be lowered to around $100-200/GJ.[367]

6.2.2 Inability to manage risk

Participants can face price risk in the DWGM through the ex ante commodity market and the uplift charging arrangements. The AEMC notes that market participants can face volume risk when transmission pipelines become constrained, although we understand this risk is low and, as the issue has not been raised to date, is not discussed further.

DWGM market participants may also face volume risk associated with exporting gas from Victoria. While the AEMC considers there would be merit in investigating these issues further in the DWGM review, given the potential for these market design and interoperability factors to impede the efficient trade and movement of gas out of Victoria, our detailed consideration of these issues can be found in Chapter 4.

Ex ante price risk

With relatively stable gas supply and demand conditions in the east coast market historically, participants have generally traded gas on the DWGM within the confines of their bilateral contracts, with the contracts acting as a natural hedge against price

363 GDFSAE, Discussion Paper submission, p. 9.

364 APGA, Discussion Paper submission, p. 24; APA, Discussion Paper submission, p. 1; and Major Energy Users, Discussion Paper submission, p. 4.

365 QGC, Discussion Paper submission, p. 6.

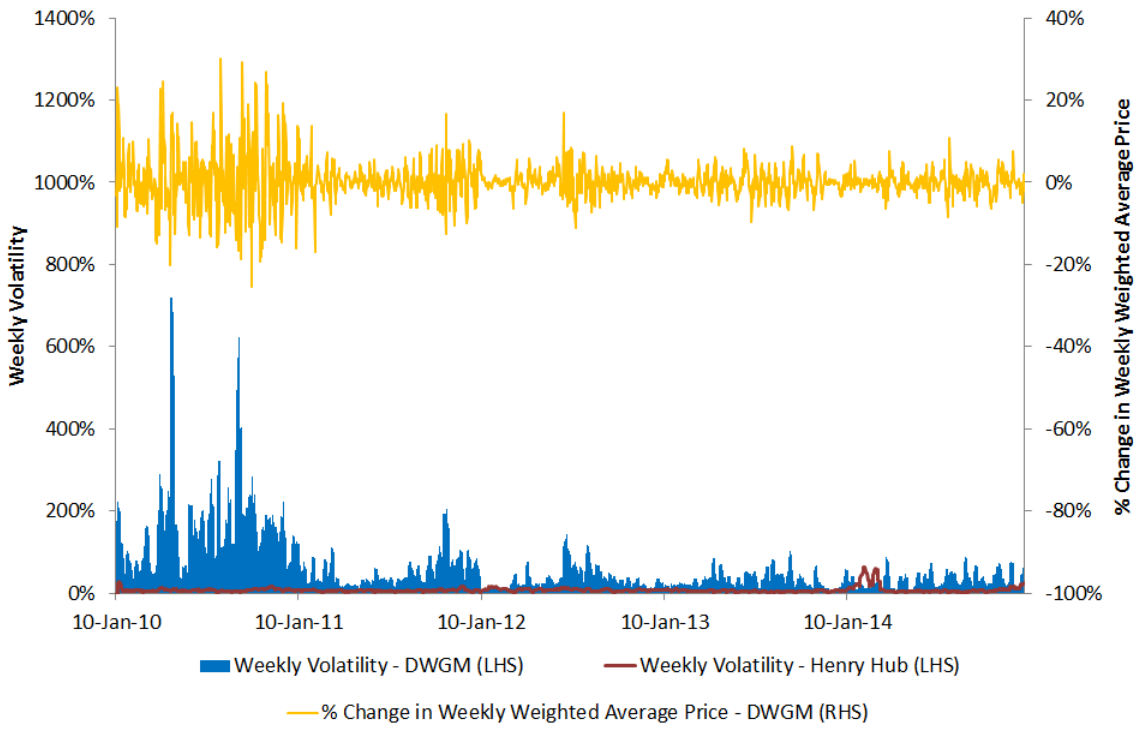
366 GDFSAE, Discussion Paper submission, p. 10.

367 ERM Power, Discussion Paper submission, pp. 7-8.

risk. For example, a large industrial user with a GSA will effectively be selling and buying the gas to itself at whatever the price is in the DWGM and, thus, will be perfectly hedged from the ex ante price.[368]

Price risks emerge when participants use the ex ante commodity market to sell or purchase gas outside of their contractual positions. For example, a retailer who has expected demand of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ and bid to withdraw 100 TJ in the ex ante market. In this case, the retailer will be exposed to ex ante price risk on 20 TJ via an imbalance payment,[369] which is the volume of gas not supplied under a long-term contract.

Figure 6.3 DWGM spot price has been highly volatile historically



Source: AEMC volatility analysis based on price and volume data sourced from AEMO (for the DWGM) and price data sourced from EIA (for the Henry Hub). DWGM daily and weekly average prices were calculated by weighting schedule prices by traded volumes. Weekly volatility was calculated using the methodology set out in: EIA, *An Analysis of Price Volatility in Natural Gas Markets*, August 2007.

Note: Volatility is driven by per cent differences in prices of gas between days across a rolling week. Large absolute price movements at higher prices may equate to a comparable level of volatility as a smaller price movement when natural gas prices are lower. Further, increasing natural gas prices do not necessarily indicate whether a market is volatile, since volatility is defined by the degree of price variation in the market, not by the level of prices or direction of price movements. See: EIA, *An Analysis of Price Volatility in Natural Gas Markets*, August 2007, p. 1.

As can be seen from Figure 6.3, the DWGM has experienced periods of very high ex ante price volatility historically and can be considered to be a highly volatile price

368 While we note market participants may be perfectly hedged from the ex ante price through their contract positions, they may still be exposed to uplift charges. The risk participants face from these charges is outlined in the section below. Uplift charges are outlined in detail in Appendix F.

369 The details of how imbalance payments work in the DWGM can be found in Appendix F.

generally. Compared to one of the most liquid gas trading hubs internationally - the Henry Hub in North America - volatility is understandably higher in the DWGM due to the smaller number of participants and volumes of gas traded.

As supply and demand conditions on the east coast become more dynamic, there are likely to be greater opportunities for participants to trade gas on a short-term basis, outside of their contract positions. To trade gas on a spot commodity basis, participants require a means to be able to manage their exposure to the price risk, something they cannot currently do for any gas traded outside of their contracts on the DWGM.

In 2009, the Australian Stock Exchange (ASX) introduced a number of derivative products that are linked to the price payable at the beginning of the day in the DWGM.[370] However, these products are rarely traded, which is likely to be because the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream producers, and then selling it to themselves through the DWGM using bilateral contracts (and/or participants are choosing to just not use them). In addition, these ASX products only provide a hedge against the 6.00am ex ante price[371] (as determined with reference to the beginning of the day prices) and not against any uplift charges.[372]

Uplift charge risk

While market participants holding AMDQ or AMDQ cc[373] can use part or all of these limited rights as a partial hedge against congestion uplift charges, those that do not hold these instruments have no means to hedge against congestion uplift charges. In addition, market participants, whether they are holders of AMDQ or not, cannot hedge against surprise or common uplift charges.[374]

Observations from previous reviews

As part of the Victorian Gas Market Taskforce review, most stakeholders raised the need for greater transparency in forward gas prices in order to facilitate planning and risk management. In particular, some stakeholders were of the view that the DWGM

370 These products are currently: (1) Victorian wholesale gas futures (in units of 100 GJ of natural gas per day over the period of a calendar quarter); (2) Victorian wholesale gas strip futures (units are four Victorian wholesale gas futures contracts); and (3) Strip options over Victorian wholesale gas futures (an option over four predetermined Victorian wholesale gas futures contracts).

371 Ex ante prices are set at five discrete times during the gas day in the DWGM (6.00am, 10.00am, 2.00pm, 6.00pm and 10.00pm) . See: Appendix F.

372 ASX Victorian Wholesale Gas Futures contracts are cash settled using the arithmetic average of the beginning of the day (6.00am) price for the Victorian wholesale gas market over the period of a calendar quarter.

373 Unlike contract carriage pipelines, shippers utilising the DTS cannot reserve firm capacity. They may, however, have an AMDQ allocation or an AMDQ cc, which provide them with a hedge against congestion uplift charges. AMDQ and AMDQ cc (and the rights they provide holders) are outlined in detail as part of Appendix F.

374 Uplift charges are further discussed in Appendix F.

spot price cannot be adequately hedged by futures products because of uplift charges.[375]

Stakeholders consulted with as part of the AEMC's Scoping Study noted that while AMDQ provides participants that have an allocation with some protection against congestion uplift charges, AMDQ cannot be used to hedge against surprise or common uplift charges. Reference was also made in this context to the ASX Victorian Wholesale Gas Futures product, but participants stated this product can only be used to hedge against the ex ante market price and not uplift charges and was not therefore widely used.[376]

Stakeholders also noted that the methodology used to allocate congestion uplift charges in the DWGM should be reviewed to determine whether it is consistent with the 'causer pays' principle, particularly in those circumstances where the ancillary payments have been incurred as a result of a system constraint or supply source failure and participants without a hedge have been withdrawing gas in line with their schedule.[377]

In the ESAA's assessment of the east coast gas market stakeholders stated that prices on the DWGM (and STTM hubs) primarily reflect daily imbalance positions of market participants, rather than underlying conditions of supply and demand. Stakeholders suggested that the observed market prices may therefore provide some insight to a potential new entrant, but are likely of little value in terms of actual benchmarks for contract negotiations. Overall, stakeholders suggested that the facilitated markets have had little impact on transparency in the commodity and transport markets.[378]

Stakeholder submissions to the Discussion Paper

Risk management and price transparency was a key theme emerging in submissions received. Issues raised largely fell within the following two categories:

1. Ex ante prices in the DWGM do not reflect all costs (ancillary payments) and impede the development of risk management products; and

2. Uplift payments not allocating 'costs to their cause'.

Ex ante prices in the DWGM do not reflect all costs (ancillary payments) and impede the development of risk management products

Many parties that made submissions were of the view that the current ancillary payment/uplift charging regime in the DWGM was complex and that these costs should be incorporated in the observed market price. Many submitters were of the view that this would encourage the development of risk management products.

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375 Victorian Government, *Gas Market Taskforce,* Supplementary Report, October 2013, p. 105.

376 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 95.

377 K Lowe Consulting, *Gas Market Scoping Study,* a report for the AEMC, July 2013, p. 97.

378 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform,* May 2013, pp. 58 & 60.

ERM Power states that the DWGM is far more complex than the STTM and Wallumbilla GSH, particularly the settlement process, and believes that its complexity could be simplified considerably via the ancillary payment/uplift calculation processes. ERM Power points to these processes being explained in four AEMO procedural documents, which total 144 pages with numerous complex algorithms.[379]

ERM Power proposes a move away from the current unconstrained pricing regime (with ancillary payment/uplift charges) because it exposes market participants to risks they cannot manage.[380] ERM Power added that if all costs were reflected in the spot price, swaps and other derivatives (eg the ASX products) would be more effective in allowing participants to manage their risks. ERM Power states that if all costs (or the majority of costs) were reflected in the spot price, the attractiveness of financial hedging in the DWGM would increase.[381]

While AGL's view is that the DWGM is generally best left alone, it also states that there is significant complexity and risk in the ancillary payments/uplift charge process. AGL would welcome a review of these charges with the aim of reducing market participants' transaction costs and pricing risks.[382]

GDFSAE states moving to an arrangement whereby the costs associated with ancillary payments are embedded in the market price (providing participants a 'clean' price signal) will encourage greater levels of participation and liquidity.[383] In an industry statement presented to the AEMC, the signatories also noted these points stating that the current situation of multiple market designs make trading complex and inefficient and that it differs to a widely accepted market with 'clean' prices that encourages greater participation and liquidity.[384]

The ESAA also notes that the complexity of ancillary payments and uplift charges could be reduced via linking them to the market price and that this could improve participants’ ability to assess and manage risk. The ESAA considers this would likely improve the value and uptake of risk management products such as those offered by the ASX and increase market transparency.[385]

Origin Energy, like ERM Power and GDFSAE, suggests that the current pricing structure is not truly reflective of market costs and a key means to manage risk in the STTM and DWGM is to ensure all market costs are incorporated in the price. Origin Energy notes that there are a number of prices on any given day, which increase

379 ERM Power, Discussion Paper submission, p. 7.

380 ERM Power, Discussion Paper submission, p. 6.

381 ERM Power, Discussion Paper submission, p. 7.

382 AGL, Discussion Paper submission, p. 5.

383 GDFSAE, Discussion Paper submission, pp. 8-9.

384 Industry Statement, Discussion Paper submission, p. 3. Note: the Industry Statement was supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association.

385 ESAA, Discussion Paper submission, p. 7.

operating costs and give rise to risks that cannot be effectively hedged. In the DWGM this could take the form of linking ancillary payments back to the market price, which would improve the ability of market participants to assess and hedge risk (and make ASX products more highly traded).[386]

Uplift payments not allocating 'costs to their cause'

ERM Power disagrees that the allocation of ancillary payments is currently done on a "cost to causer" basis, particularly for congestion uplift. ERM notes that "when ancillary payments are generated, a portion of the total cost is always allocated as congestion uplift with the residual being allocated as surprise and common uplift, regardless of the nature of the event that has caused the cost".[387]

ERM Power further states that congestion uplift charges unfairly penalise small market participants and new market entrants. It is suggested that current market forecasts (supply shortages) make it very difficult for these parties to secure the right combination of physical supply and AMDQ cc/AMDQ to give effect to a congestion hedge.[388]

ERM suggests that a rule is made that removes congestion uplift changes and makes all ancillary payments recoverable through common and surprise uplift charges.[389]

6.2.3 Transaction costs associated with the value adding market functions

Costs incurred by AEMO in its role as operator of the DWGM are recovered from participants by charging a fee for gas withdrawn from the DTS. Since participation in the DWGM is mandatory for parties wishing to withdraw gas, this fee reflects an unavoidable transaction cost for these parties.

The fee is currently $0.082/GJ for the DWGM and is budgeted to rise seven per cent in 2015-16.[390] AEMO has reported that expenditure in 2015-16 is expected to be $21.8 million with approximately 65 per cent of this comprised of labour costs ($14.1m).[391]

In general, the costs associated with a centrally administered market should primarily be recovered from the beneficiaries of those markets via the trades that have occurred as a direct result of the market being in place.

As can be seen from Figure 6.1, the majority of gas transacted through the DWGM is by participants who are selling gas into the market and at the same time buying it back. This is because, while the DWGM is compulsory, most participants have underlying

386 Origin, Discussion Paper submission, pp. 2-3.

387 ERM Power, Discussion Paper submission, pp. 3-4.

388 ERM Power, Discussion Paper submission, p. 4.

389 ERM Power, Discussion Paper submission, p. 5.

390 AEMO, *Consolidated Draft Budget and Fees: 2015-16*, Published March 2015, p. 14.

391 AEMO, *Gas Market Draft Budget and Fees 2015 - Vic Wholesale Gas and VIC Gas FRC*, March 2015, p. 8.

gas supply agreements in place and do not need to use the DWGM for the majority of their needs.

If the annual costs of operating the DWGM were only recovered from gas that is traded for the purposes of settling ex ante commodity trades and ex post deviation trades, the historical AEMO fee rises from approximately $0.07-0.09/GJ to approximately $0.35-0.40/GJ for the DWGM, as shown in Table 6.1 below. These indicative cost estimates are relatively high in the context of gas prices typically observed in the DWGM of around $4/GJ (ie, approximately 10 per cent). It also does not include the costs associated with the time and resources individual firms must dedicate to operating in the DWGM, or the effects of any penalties (such as uplift payments).

The current structure for recovering AEMO's costs of operating the DWGM has, arguably, resulted in those trading mostly in balance (where injections equal withdrawals) being charged a disproportionate amount, relative to those who rely more on the ex ante commodity and balancing functions. This is evident historically in the difference between the market fees of approximately 7 – 9 cents per GJ and the approximate 35 – 40 cents per GJ that would have been levied if the costs of the market were only recovered from the trades facilitated by the DWGM.

Table 6.1 AEMO $/GJ DWGM fees would be significantly higher if levied only on ex ante commodity and ex post deviation trades

	2010-11	2011-12	2012-13	2013-14
AEMO expenditure ($m)	16.6	17.2	18.1	20.4
Total withdrawals (PJ)	232.2	220.5	228.3	224.2
Ex ante commodity and ex post deviation trades (PJ)	44.4	43.1	53.1	55.7
Implied AEMO fee ($/GJ) – based on total DWGM transactions*	0.07	0.08	0.08	0.09
Implied AEMO fee ($/GJ) – based on ex ante commodity and ex post deviation trades	0.37	0.40	0.34	0.37

Source: AEMC analysis using AEMO supplied expenditure and gas trade data.

* Note that prior to 1 July 2014, the tariffs for Tariff D and Tariff V customers were separately specified. We have estimated the implied tariff for *all* customers for the years in the above table to ensure a consistent comparison to the current $0.082/GJ rate for all customers.

However, as noted in section 5.2.3, in presenting this analysis, which is based on the best data available to the AEMC at the time of conducting this review, we note three important caveats:

1. **Completeness of underlying data:** As discussed in section 5.2, since publication of the draft report the Commission has been made aware that the number of ex ante trades may have been underestimated for the STTM. While similar issues have not been raised by any party for the DWGM to date, the Commission

considers it prudent that this analysis is also treated as an order of magnitude assessment.

2. **Need for another form of balancing mechanism:** In the absence of the DWGM, another form of balancing mechanism would need to be implemented to manage 'unders and overs'. Therefore, while this analysis has considered the absolute costs of the DWGM on participants, it has not looked at the avoided costs, which would need to consider the costs of an alternative balancing mechanism.

   AEMO raised this in its submission to the Stage 1 Draft Report noting that, in addition to facilitating inter-participant trades, the DWGM also provides a market-based balancing mechanism for participants that, given the retail market, would be required (in some form) regardless of the wholesale market's structure. AEMO further notes that, through its system operation role and through the scheduling of the market, the DWGM plays a role in maintaining system security and for participants reducing the risk of curtailment.[392]

3. **Lowering barriers to entry and increasing competition:** Direct costs of the DWGM may be outweighed by the additional flexibility provided to new entrant retailers and large industrial users of gas, who could choose to purchase some or all of their gas requirements through the market instead of directly from producers or retailers. This optionality could lower barriers to entry and promote competition in relevant downstream markets, such as gas retailing, creating benefits for consumers.

Observations from previous reviews

In the Scoping Study, most stakeholders noted that the DWGM provides an effective mechanism for trading imbalances and were of the view that the movement to ex ante intra-day trading in 2007 was a positive step forward.[393]

The Victorian Gas Market Taskforce stated that the DWGM spot market has not been successful in stimulating commodity trading of gas (relative to the UK's National Balancing Point). In particular, the review referred to the fact that gas is sold to retailers under bilateral contracts and only bid into the market by those retailers and so the spot market is used as a balancing market only, which was stated to underutilise the potential of the DWGM to achieve greater transparency and efficiency.[394]

Views expressed on the facilitated markets in general as part of the ESAA's assessment of the east coast gas market prepared by Deloitte were largely that out of contract trades made up only a very small proportion of total trades on these markets. Stakeholders indicated that actual trading activity *between* participants on the facilitated markets is relatively limited, with the markets primarily serving the function

392 AEMO, Stage 1 Draft Report submission, p. 4.

393 K Lowe Consulting, *Gas Market Scoping Study,* A report for the AEMC, July 2013, p. 95.

394 Victorian Government, *Gas Market Taskforce,* Supplementary Report ,October 2013, p. 79.

of balancing mechanisms, rather than as an alternative wholesale source of gas to their upstream contracts.[395]

The ESAA review estimated that most wholesale buyers would typically contract up to around 95 per cent of their expected demand requirements on the STTM hubs and around 80 per cent on the DWGM (possibly less in the case of smaller retailers). A cost of $0.50/GJ traded was estimated as part of this review for the DWGM based on an assessment of volumes traded, deviation costs and market revenue requirements.[396]

Discussions with stakeholders as part of the ESAA review suggested that higher levels of out of contract trading on the DWGM than the STTM hubs relate primarily to the perception of the DWGM as a more mature and less risky market for the following reasons:[397]

- Higher liquidity, with significantly more gas withdrawn and traded on the DWGM than in the STTM hubs combined, plus the ability to adjust trading positions during the gas day with intra-day trading.
- More opportunities for managing operational risks, with the ability to enter into contracts with storage providers (including LNG) for on call injections or withdrawals.
- A co-ordinated approach to market and transmission scheduling. AEMO is responsible for both market scheduling and operation of the DTS. This dual role reduces the risk of pipeline allocations differing from the market schedule as can occur in the STTM hubs.
- The demand profile of wholesale buyers in Victoria, where there is a greater proportion of (less predictable) residential demand relative to all other STTM hubs (with the possible exception of Adelaide).

While overall trading outside of contractual arrangements was stated to be limited, a number of stakeholders noted in the ESAA review that the facilitated markets have played a key role in supporting the entry of new retailers on the east coast. In particular, it was noted that the ability to obtain access to gas in the initial phase of market entry without needing to commit to a long-term GSA and GTA in the DWGM was critical to getting a foot-hold in the retail market, and developing the experience and scale necessary to enter into a long-term GSA and GTA.[398]

395 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, p. 44.

396 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, p. 61.

397 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, p. 45.

398 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, pp. 45-46.

The Eastern Australian Domestic Gas Market Study notes that the DWGM was designed to complement long-term gas contracts and provide an option for making up short run supply and demand shortfalls. The report identifies that the DWGM currently trades insignificant gas volumes and may have only a limited relevance to the price of the long-term gas contracts.[399]

Stakeholder submissions to the Discussion Paper

Most stakeholders submitted that the facilitated markets are generally working well and provide an effective mechanism to trade imbalances. However, many also noted that the DWGM (like the STTM) provides a mandatory balancing market that participants must use and pay for, regardless of whether there is intent to use the balancing services or not.

APGA noted that gas traded on the facilitated markets represents only a very small portion of the total traded at the wholesale level, which is primarily conducted through bilateral contracting.[400] APGA quote trading in balancing gas as making up approximately 13 per cent of the DWGM in 2014-15 and, that if the current $0.08/GJ gas fee was spread over just the balancing gas, the cost would increase to approximately $0.61/GJ.[401] APGA notes that the current fee structure results in participants - that do not need to use the balancing service - subsidising those that do.[402]

Similarly, ESAA also notes that the DWGM and STTM hubs impose relatively high costs per GJ traded on account of the low volume of gas traded, with market participants generally seeking to closely match their own injections and withdrawals to minimise exposure to significant financial risks that cannot be hedged. ESAA refers to an estimate of approximately $0.50/GJ traded for the DWGM from the 2013 report ESAA commissioned Deloitte to produce (discussed below). ESAA noted that reducing transaction costs is essential to improve trading and liquidity and ensure the facilitated markets deliver value to market participants in the future.[403]

AGL notes that the facilitated markets are essentially balancing arrangements in downstream distribution networks and that "the [facilitated] markets are characterised by complexity and resultant overhead costs which culminate in a service cost per GJ, particularly in the STTM, which overwhelm any value to be had from trading in the market".[404]

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399 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 64.

400 APGA, Discussion Paper submission, p. 11.

401 APGA, Discussion Paper submission, p. 34.

402 APGA, Discussion Paper submission, p. 30.

403 ESAA, Discussion Paper submission, p. 3.

404 APGA, Discussion Paper submission, p. 1.

6.3 AEMC's Stage 1 findings and recommendations

This section summarises submissions received to the Stage 1 Draft Report and sets out the Commission's findings from this part of the review, as well as details on the direction for Stage 2 and the standalone DWGM Review.

Stage 1 recommendations are also provided as required under the Commission's terms of reference and represent "no regrets" changes where implementation can begin immediately - irrespective of the future development of the DWGM and its role in the broader east coast gas market framework.

6.3.1 Submissions to the Stage 1 Draft Report

The draft report recommended that consideration be given during Stage 2 of the review as to whether the original objectives of the DWGM remained relevant and, if so, whether the market was meeting those objectives. Two recommendations that could begin to be implemented immediately were also identified for consultation with industry, namely:

1. removing the limitation in the NGL on who can submit DWGM rule changes; and

2. harmonising gas day start times.

This section discusses the views raised in submissions on the direction of the Stage 2 report with respect to the DWGM and these recommendations.

Stakeholder views on the direction for Stage 2 and the standalone DWGM Review

The majority of parties that made submissions to the Stage 1 Draft Report were supportive of the idea that now is an opportune time to review the current design of the DWGM. A number of parties submitted that if a technical working group was established to assess the potential simplification of the STTM design, then it should also examine the DWGM in the same light.[405]

As outlined in section 5.3.1, industry stakeholders have largely expressed support for the AEMC establishing a long term strategy for the development of the facilitated markets on the east coast.[406] Stanwell and Hydro Tasmania both made the point that the AEMC should consider long term visionary changes to the market instead of

405 ESAA, Stage 1 Draft Report submission, p. 4; and EnergyAustralia, Stage 1 Draft Report submission, p. 3.

406 Origin, Stage 1 Draft Report submission, p. 5; APA, Stage 1 Draft Report submission, p. 17; Alinta Energy, Stage 1 Draft Report submission, p. 3; ESAA, Stage 1 Draft Report submission, p. 5; AEMO, Stage 1 Draft Report submission, p. 4; Santos, Stage 1 Draft Report submission, p. 4.

continuing to support the piecemeal development to date, and that a clear long term strategy is required.[407]

A number of parties expressed differing views on a potential redesign of the DWGM in order to achieve a more focussed balancing market. For example:

- EnergyAustralia states a concern that the review proposes to reduce the volume of trade through the DWGM and STTM;[408]
- APA supports a more in depth analysis of the DWGM and its future role and structure. APA considers gas trading is very limited in the DWGM and the market operates primarily as a mechanism to allocate pipeline capacity and trade imbalances;[409] and
- Origin supports the view that the balancing aspect of the DWGM be harmonised with that in the STTM and the commodity element with the GSH.[410]

A number of parties support considering the originally stated objectives of the DWGM. Origin for example considers there is merit in considering whether the originally stated objective of the DWGM remains relevant and whether the current market design is considering those objectives efficiently, and if not, whether the objectives and design need to be reconsidered.[411] AGL states that the AEMC should consider whether the existing intra-day trading design is fit-for-purpose, given gas-fired generation has not had as significant an impact on the Victorian gas market as expected.[412]

As outlined in section 5.3.3, a number of submissions suggest that the AEMC has already decided on an appropriate market structure for the east coast and/or favoured a model for certain facilitated markets (in particular for the STTM).[413] The AEMC notes that this is not the case and the intention is to use the DWGM Review and Stage 2 of the East Coast Review to assess the current east coast market design against a range of alternate market designs and make recommendations to the Energy Council around the future development of DWGM, STTM, GSH and other aspects of the market, such as information provision and pipeline capacity trading.

407 Stanwell, Stage 1 Draft Report submission, p. 1; Hydro Tasmania, Stage 1 Draft Report submission, p. 2 & 4.

408 EnergyAustralia, Stage 1 Draft Report submission, p. 3.

409 APA, Stage 1 Draft Report submission, p. 15.

410 Origin Energy, Stage 1 Draft Report submission, p. 4.

411 ibid.

412 AGL, Stage 1 Draft Report submission, p. 3.

413 Major Energy Users, Stage 1 Draft Report submission, p. 3; CQ Partners, Stage 1 Draft Report submission, p. 6; and Qenos, Stage 1 Draft Report submission, p. 2.

Stakeholder views on removing the limitation in the NGL on who can submit DWGM rule changes

All submissions addressing this issue were supportive of removing the current limitation from the NGL. No party expressed a preference to retain the current limitation in the NGL.

GDFSAE, the MEU, Santos, the ESAA, Visy and Jemena all state support for removing the current NGL limitation on who can make applications for rules changes for rules regulating the DWGM.[414] AGL and Origin Energy state support for removing the current limitation, with AGL noting this is on the assumption that there is no additional cost impact to market participants.[415]

EnergyAustralia supports removing this limitation but states that it may be better to delay this change until the completion of the review to ensure that rule change are considered in the context of the overall gas market development strategy.[416]

Stakeholder views on harmonising the gas day start time

As discussed in section 5.3.1, the majority of submissions considered that gas days should be aligned for all facilitated markets on the east coast. No submissions were opposed to the alignment.

Some parties highlighted a number of one-off costs associated with implementing a harmonised gas day start time.[417] However, it is also generally considered that these costs are likely to be less than the long term benefits of a single gas day start time regime as the integration of the east coast market continues, although sufficient lead time will be required to implement system changes.

Further, while the majority of submissions considered that gas days should be aligned for all facilitated markets on the east coast, only a few submitted a specific start time and there was no real consensus in those that did.[418] We also understand from AEMO that the current 6:00am start time for the DWGM means that the first reschedule of the day (ie, 10:00am) occurs after the typical mid-morning peak and so minimises uncertainty for participants.

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414 GDFSAE, Stage 1 Draft Report submission, p. 5; MEU, Stage 1 Draft Report submission, p. 2; Santos, Stage 1 Draft Report submission, p. 3; ESAA, Stage 1 Draft Report submission, p. 5; Visy, Stage 1 Draft Report submission, p. 7; and Jemena, Stage 1 Draft Report submission, p. 3.

415 AGL, Stage 1 Draft Report submission, p. 3; Origin Energy, Stage 1 Draft Report submission, p. 3.

416 EnergyAustralia, Stage 1 Draft Report submission, p. 3.

417 APA, Stage 1 Draft Report submission, p. 2; Origin, Stage 1 Draft Report submission, p. 3; Stanwell, Stage 1 Draft Report submission, p. 6; and AEMO, Stage 1 Draft Report submission, p. 5.

418 AGL, Stage 1 Draft Report submission, p. 3; Santos, Stage 1 Draft Report submission, p. 3; EnergyAustralia, Stage 1 Draft Report submission, p. 3; QGC, Stage 1 Draft Report submission, p. 2; and APA, Stage 1 Draft Report submission, p. 14.

6.3.2 Final Stage 1 findings

The DWGM is generally regarded by participants as providing an effective and competitive gas balancing service and facilitating trading of gas in Victoria based on short-term prices. The DWGM and associated market carriage arrangements in Victoria are widely regarded as being more conducive to market entry and promoting retail competition than the STTM and contract carriage model.[419]

While the original market design has been developed on an incremental basis since market-start, the underlying fundamental structure remains unchanged – a set of arrangements designed to offer a balancing trading service, a spot commodity trading service and to allocate capacity on the DTS.

Feedback from some stakeholders and analysis undertaken by the AEMC indicates that the costs of operating in the current DWGM may potentially impose a disproportionate administrative burden on the market. This is because those participants who trade within their bilateral contracts incur a fee for participating in the market, irrespective of whether they derive any value from the arrangements.

The DWGM also represents an added level of complexity for entities wishing to operate both inside and outside of Victoria since it is characterised by a different set of market arrangements to the STTM operating in other demand centres, although the practical roles of each market are similar.

Many stakeholders also consider that there is significant complexity and risk associated with ancillary payments and uplift charges in the DWGM. Reducing the complexity of these arrangements may therefore improve participants' ability to assess and manage risk.

6.3.3 Final Stage 1 recommendations

As part of Stage 1 of the East Coast Review, the Commission is required to give consideration to whether there are any existing issues that can be resolved with the intention of better placing the DWGM to achieve the NGO, irrespective of what future shape the facilitated market arrangements in Victoria take (the outcome of Stage 2).

Specifically, the AEMC has considered issues raised in submissions to the Discussion Paper and the Draft Stage 1 report, as well as applying its own analysis and assessment framework outlined in Chapter 2, and recommends:

1. removing the limitation in the NGL on who can submit DWGM rule changes; and

2. harmonising gas day start times.

419 K Lowe Consulting, *AEMC 2014 Retail Competition Review: Retailer Interviews*, Report for the AEMC, June 2014, pp. 18, 22, 25, & 30.

The Commission is of the view that the implementation of these recommendations can begin immediately. Each of these is discussed below.

Remove limitation in the NGL on who can submit DWGM rule changes

Section 295(3) of the NGL establishes two restrictions on who can make a rule change request relating to the Victorian gas arrangements. Section 295(3)(a) provides that a request for a rule regulating the DWGM may only be made by AEMO or the Minister of an adoptive jurisdiction. Section 295(3)(b) provides that a request for a rule regulating in some other way the declared system functions may only be made by AEMO, a service provider for the DTS that is a party to a service envelope agreement with AEMO or the Minister of an adoptive jurisdiction.[420]

AEMO's declared system functions are specified in 91BA(1) of Division 2 of Part 6 of the NGL. They include the operation of the DWGM, but also include a range of other functions primarily related to the operation and security of the DTS.

The Commission recommends that the Energy Council develop and implement changes to the NGL to delete s295(3)(a). This will bring the process for making rule change requests relating to the DWGM in line with the current open standing process applying to the STTM, as well as that applying to the electricity sector through the National Electricity Rules. The retention of the restriction in s295(3)(b) would also be consistent with the arrangements in the National Electricity Law (NEL).[421]

A practical implication of deleting 295(3)(a) from the NGL will be that, when a rule change request is made concerning Part 19 of the NGR, the AEMC will have to decide whether it is a request for a rule regulating the DWGM (which would be allowed) or whether it was a request for a rule regulating in some other way the declared system functions (which would be restricted to AEMO, the Victorian Minster or the service provider for the declared transmission system that is a party to a service envelope agreement with AEMO).

To help guide this decision, and to simplify the drafting of s295, we therefore recommend that the Energy Council also make changes to the NGL to split out AEMO's DWGM functions from its other declared system functions.

Specifically, we recommend that the NGL is changed to split AEMO’s declared system functions as currently set out in s91BA(1) into two separate subsections: one listing AEMO’s DTS system operation/system security functions (retaining the title "AEMO’s declared system functions")[422] and one listing AEMO’s functions relating to the operation and administration of the DWGM.[423] The remaining restriction set out in

420 Victoria is the only adoptive jurisdiction.

421 Section 91(7) of the NEL states that a request for a rule regulating AEMO's declared network functions may only be made by AEMO, a declared transmission system operator that is a party to a network agreement with AEMO, or the Minister of an adoptive jurisdiction. Victoria is again the only adoptive jurisdiction.

422 These are currently listed as s91BA(1)(a)-(e).

423 Currently s91BA(1)(f)-(g).

s295(3)(b) could then be redrafted to refer simply to "a request for a Rule regulating the declared system functions".

Harmonise gas day start times

The Commission recommends the Energy Council submit a rule change request to set gas day start times to 6.00am, in line with the DWGM. This recommendation is discussed in section 5.3.3.

6.3.4 Stage 2 direction and standalone DWGM Review

Taking into account feedback from stakeholders, and given the changes underway in the east coast market, the Commission considers it is an opportune time for reflection on the role of the DWGM (and STTM and GSH) in the broader east coast gas market, including setting out a development plan for the market into future.

In particular, we consider there is an exercise that needs to be undertaken in considering the following issues as part of Stage 2 of the review:

1. the originally stated DWGM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and

2. if not, whether the objectives and design of the DWGM need to be re-focussed, taking into account developments in the broader east coast market and the DWGM role alongside other facilitated markets.

The Commission will progress these issues as part of the coincident DWGM Review being undertaken by the AEMC.[424] Over the second half of 2015 we intend to progress this as a standalone review, although there will be important linkages to the East Coast Review. As such, the analysis will be integrated across the two reviews.

A major area of focus for the DWGM Review will be to understand whether improvements can be made to the liquidity of trading and the pricing mechanism in the DWGM. In line with the Energy Council's Vision, we will consider the extent to which the DWGM can provide an efficient reference price and how this might be achieved. To do so may involve establishing whether energy prices can be separated from balancing and uplift charges, and assessing the effects of the current range of prices, including the intra-day rescheduling of the market.

Another major element of this work will be to examine the potential to introduce capacity rights to the DWGM, with the objective of better facilitating market-led investment in network expansion. Allowing participants to signal the need for capacity augmentation would be likely to result in more efficient investment, and would transfer risk away from consumers to parties better able to manage it. The extent to

[424] The Terms of Reference for the DWGM Review can be found on the AEMC website, available at: http://www.aemc.gov.au/getattachment/2f8734f1-4286-4672-b72e-aabab078d6fa/Terms-of-Reference.aspx

which this facilitates inter-regional trade with adjoining markets will also be an important factor in our assessment.

We intend to commence this work with the publication of a paper for consultation in August/September 2015 and a Draft Report in December 2015. The paper for consultation will further investigate the key areas of concern and clearly define the issues, as well as setting out some high level options for consideration. These options are likely to include incremental improvements, as well as more substantial changes such as those previously recommended for implementation by VENCorp[425] and options drawing on international experience.

A Final Report will be published in 2016 following receipt of the Victorian Government's response to the findings and recommendations in the Draft Report. The timing and inter-linkages between the various inputs to the DWGM Draft Report and the Stage 2 Draft Report are shown in the figure below.

Figure 6.4 Timeline for inputs to the Stage 2 Draft Report and the DWGM Draft Report

425 VENCorp was the predecessor body to AEMO in operating the DWGM.

7 Gas Supply Hub

Box 7.1 Summary of findings and recommendations

While the Wallumbilla GSH has only been operational for around 16 months, and the volume of trades occurring is relatively low, participants are generally of the view that the market provides a simple and low cost platform for the trading of gas. However, we note that participants can avoid using the market if they choose to and only face transaction costs if trades are completed.

As the Wallumbilla GSH matures, there will be refinements to the initial design that need to be made consistent with any fledgling market. An example of this can be seen in AEMO's work to consolidate the three current trading locations at Wallumbilla into a single product. In this context, the AEMC notes the following two technical workstreams AEMO is currently undertaking:

1. establishing a single trading zone/product at Wallumbilla (including the hub services required to support this); and

2. the technical design of a GSH at Moomba.

As part of Stage 2 of this review, the Commission will look to complement AEMO's Wallumbilla GSH workstream by considering the potential for workably competitive outcomes to emerge in hub services, including the potential need for economic regulation and whether this would be possible under the NGL and NGR.

During Stage 2 the Commission will also consider the role of the Wallumbilla (and potentially Moomba) GSH within the broader east coast gas market framework, including how it is likely to interact with other markets and any potential future development opportunities additional to the work currently being carried out by AEMO.

Since publication of the AEMC's Stage 1 Draft Report, AEMO has released a high level design report for a Moomba GSH, which we understand the Energy Council will consider at its July 2015 meeting.

As discussed in Chapters 5 and 6, we are recommending the Energy Council propose a rule change to harmonise the three gas day start times across the east coast markets. Since the gas day start time for the GSH is not specified within the NGR, but instead in the exchange agreement, we are also recommending the Energy Council request the AEMC define the gas day start time for the GSH in the NGR as 6.00am.

7.1 Market overview

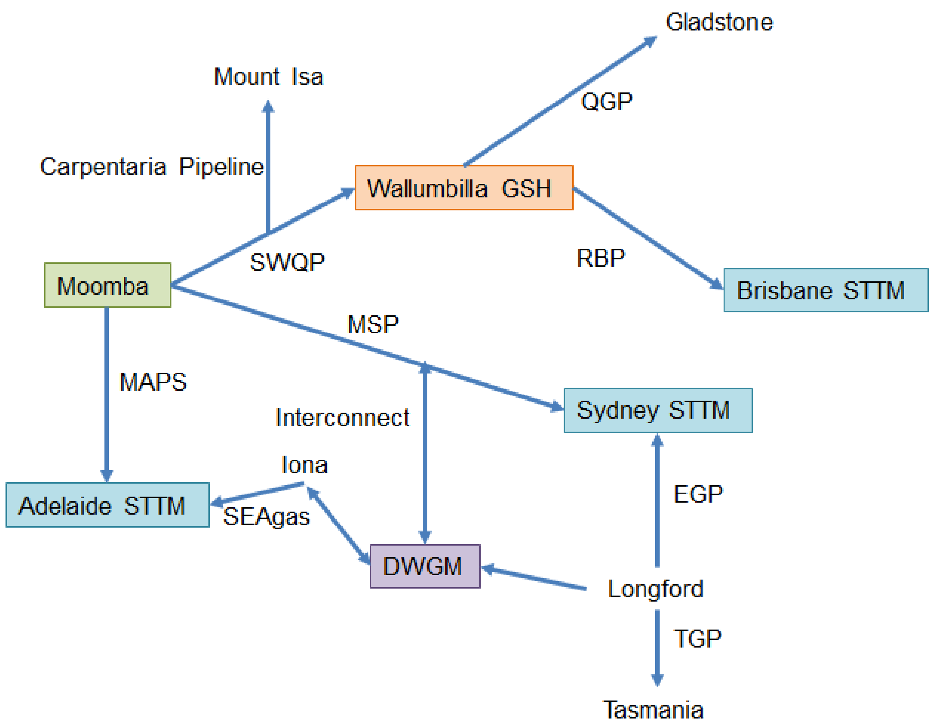
In December 2012, the COAG Energy Council announced that a new voluntary brokerage GSH would be established at Wallumbilla by March 2014.[426] AEMO was requested to develop this hub to enhance transparency and reliability of gas supply by creating a voluntary market that offers a low-cost, flexible method to buy and sell gas at interconnecting transmission pipelines.[427]

Wallumbilla was selected as a location for the supply hub because it is located in close proximity to significant gas supply and demand, and is a major transit point between Queensland and the gas markets on Australia's east coast. Wallumbilla marks the intersection of the Roma to Brisbane Pipeline (RBP), the South West Queensland Pipeline (SWQP) and the Queensland Gas Pipeline (QGP).

The figure below illustrates how Wallumbilla acts as a transit point for major gas fields and a supply point for demand centres in Gladstone and Brisbane, and is located near gas storage facilities and gas-powered generation, making it a natural point of trade.

An overview of how the three pipelines intersecting at Wallumbilla fit within the east coast gas market more broadly is shown in Figure 7.1.

Figure 7.1 Overview of the Wallumbilla supply hub and other east coast gas markets



Source: AEMC analysis.

426 SCER Communiqué, 14 December 2012.

427 AEMO website, available at: http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub.

AEMO, which was accorded responsibility for the design of the market, stated at the time of development that it expected the implementation of this hub to:[428]

- enhance the transparency of gas trading;
- improve the ability of participants to allocate and price gas efficiently in the short term;
- support the efficient trade and movement of gas between regions; and
- support the development of a financial product that can be used to manage risk.

Overall, the market was designed to provide a reference price that would support a financial derivative market to manage risk, guide investment and transaction decisions, facilitate trading through standardisation of contracts, and encourage secondary pipeline capacity trading.[429]

Products traded on the Wallumbilla GSH are for the sale and purchase of gas delivered at one of the three major connecting pipelines at Wallumbilla, ie the RBP, the QGP and the SWQP pipelines (as outlined in Figure 7.1 above). A 'trading location' has been established for each of these pipelines by grouping delivery points (either physical or virtual) to which gas is delivered and where title is transferred from a seller to a buyer.

There are currently five trading products on offer, all of which are available separately for each of the three trading locations. These products are for:[430]

- balance-of-day (today);
- day-ahead (tomorrow);
- daily (two to seven days ahead);
- weekly (next four weeks); and
- monthly (next three months).

Since the market has been in operation there have been between five and eight participants per month trading on the Wallumbilla GSH. The hub has been responsible for 3 PJ of traded gas from market-start until the end of March 2015, which, at a volume weighted average price of $2.72/GJ, equates to approximately $8.29 million in

428 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p. 4.

429 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p. 4.

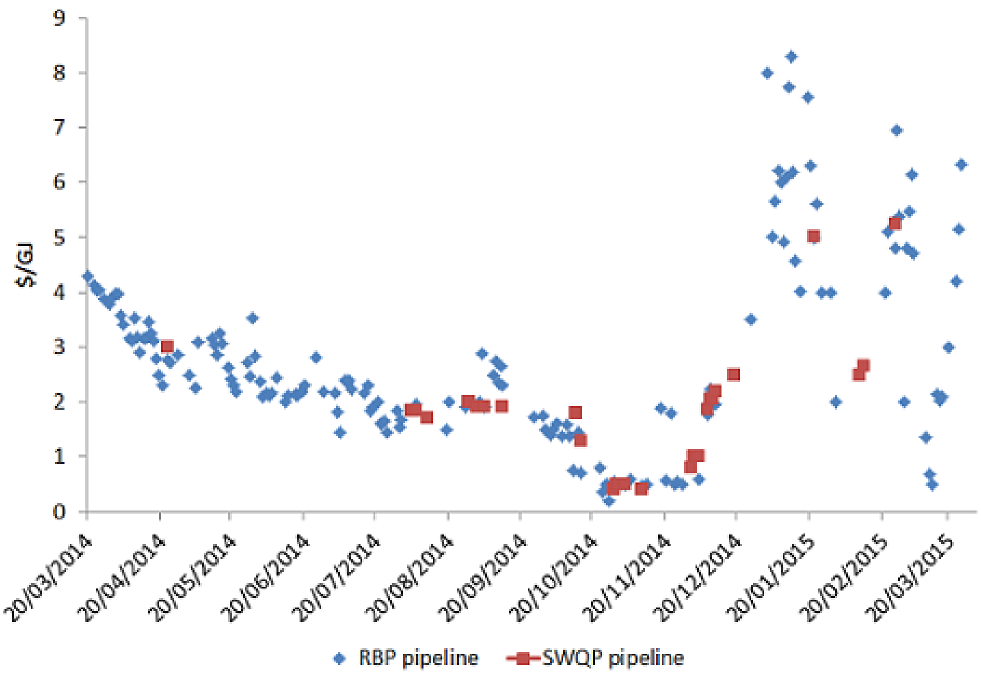
430 We understand from AEMO that it is also intending to list a monthly forward dated product later in 2015. A greater description of the products available can be found in Appendix G.

trades.[431] The 3 PJ traded since the GSH began represents approximately one per cent of total gas consumption in Queensland during 2014.[432]

To date, all trades have occurred at the RBP and SWQP nodes. While we note that the vast majority of trades to date have occurred at the RBP node, price outcomes from those trades occurring at the SWQP node do not appear to be significantly different to those on the RBP, as shown in the figure below.[433] The pattern of prices in the period following the first exports of LNG from Queensland in late 2014 differs notably from the period preceding these exports.[434]

There have also been a number of extended periods of little or no trading activity on the Wallumbilla GSH since inception. For example, there were no trades for twelve consecutive days in September 2014 and only two trades over a 21 day period at the end of December 2014 (representing 21 TJ and 3 TJ, respectively).[435] CQ Partners further states in their submission to the Stage 1 Draft Report that, as at 28 May 2015, there had been no transactions for 15 of the previous 20 trading days.[436]

Figure 7.2 Majority of GSH trades to date have occurred at the RBP node



431 AER Wholesale Statistics, available at: http://www.aer.gov.au/node/29333

432 Total gas consumption for Queensland in 2014 was estimated to be 266 PJ, see: EnergyQuest, *Energy Quarterly*, March 2015, Figure 44, p. 108.

433 The RBP pipeline delivers gas to the Darling Downs, Swanbank and Braemar 1 & 2 gas-fired generators. We understand that most trades have occurred at the RBP delivery point with trading between participants who have excess gas from these generators selling to opportunistic buyers who have the capacity to transport and store this excess gas.

434 BG Group began loading its first LNG cargo from QCLNG on 28 December 2014. See: QGC website, available at: http://www.qgc.com.au/news-media/NewsDetails.aspx?Id=5630.

435 AER Wholesale Statistics, available at: http://www.aer.gov.au/node/29333

436 CQ Partners, Stage 1 Draft Report submission, p. 6.

Source: AEMC analysis on AER, Wholesale Statistics. Data represent the daily weighted average price.

On 31 March 2015, the ASX and AEMO announced the launch of ASX Wallumbilla natural gas futures, which started trading on 7 April 2015. It was noted at the time that "participants will be able to use the Wallumbilla Gas Supply Hub Benchmark price as a basis price for their gas contracts, with the development of a derivatives market providing a risk management tool for forward pricing and planning."[437] The AEMC understand that neither of these futures products have traded to date.

Overall, while only being operational for approximately one year, most market participants are generally of the view that the Wallumbilla GSH provides a simple and low cost platform for the commodity trading of gas. As the GSH market is voluntary, participants who do not wish to trade at the hub can avoid doing so.

7.2 Key issues in the Gas Supply Hub

At the time the Energy Council agreed to proceed with the implementation of the GSH, it also agreed that a review of the model should be carried out in 2015 to consider opportunities for refinements based on operational experience, and if necessary and beneficial, consider the introduction of hub services to assist trading between the three nodes.[438]

In keeping with this decision, AEMO is currently undertaking a substantial body of work to develop the GSH and is due to report its recommendations to the Energy Council in December 2015. Aside from the current AEMO workstream, this review represents the first appraisal of the performance of the GSH and its role as part of the wider east coast gas market since the hub commenced March 2014.

The following sections set out the key issues that have been identified for the GSH, drawing on AEMO's work to date, submissions to this process and analysis undertaken by the AEMC. The issues are presented in two categories, consistent with the AEMO workstreams:

1. establishment of a single trading zone/product at Wallumbilla (including the hub services required to support this); and

2. development of a GSH location at Moomba.

7.2.1 Further development of the Wallumbilla Gas Supply Hub

As gas cannot currently freely flow between the three pipelines servicing Wallumbilla (RBP, SWBP, QGP), parties currently have to deliver/receive gas from trading

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437 ASX Media Release, 31 March 2015, available at: http://www.asx.com.au/documents/asx-news/ASX-AEMO_Launch_Wallumbilla_Gas_Futures.pdf

438 COAG Energy Council website, available at: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/gas-supply-hub-trading-market/

locations specific to each of these pipelines. There is currently no means to trade gas over the entire area that the hub encompasses.

Having multiple trading locations for essentially the same commodity traded within a small geographical area divides potential buyers and sellers of gas and limits trading liquidity. In 2012, it was estimated that investment in capacity to enable gas to flow between the facilities at Wallumbilla for a single trading model to operate successfully was approximately $118 million.[439]

AEMO is currently in the process of undertaking a review of the Wallumbilla hub with the objective of facilitating more efficient market outcomes through increased trading liquidity and participation at Wallumbilla. AEMO is investigating the development of a single product that would:

- establish a single reference price for the value of gas traded at Wallumbilla; and
- standardise the location for delivery of physical transactions.

AEMO has considered and consulted on models that could pool potential buyers and sellers together within a single market, including:

1. Single facility – grouping the delivery points on one pipeline with high throughput (eg SWQP) to form the hub definition.
2. Multiple facilities – grouping the delivery points on a small number of facilities with high throughput (eg the SWQP and RBP) to form the hub definition.
3. Single trading zone – define the hub as one virtual trading point that encompasses all gas flowing through Wallumbilla (eg SWQP, RBP and QGP).

Since publication of the AEMC's Stage 1 Draft Report, AEMO has finalised a recommended high level design for developing a single product at Wallumbilla.[440] AEMO's report recommends detailed design work begin on the multiple facilities model as it:[441]

- has the potential to maximise liquidity benefits of pooling together trading participants operating across Wallumbilla and is less disruptive to the gas industry than a single trading zone; and
- provides an opportunity to establish a market, and in turn facilitate competition, for the provision of hub services;
- builds on the existing GSH market arrangements and allows the market to continue operating under the current long-term contract framework.

439 AEMO, *Gas Supply Hub – Cost and Scoping Report*, 4 May 2012, p. 24.

440 AEMO, *Wallumbilla Single Product, High Level Design Report*, June 2015.

441 AEMO, *Wallumbilla Single Product, High Level Design Report*, June 2015, p. 4.

Notwithstanding this, AEMO continues to see potential value in undertaking a further assessment of the single trading zone design, given the potential to optimise existing hub services and the simplicity of trading gas under a single zone. However, AEMO requests that the Energy Council considers AEMO's assessment and recommendation, and provides guidance on which option(s) to progress into the detailed design phase.[442]

The detailed design phase will involve a process with stakeholders to determine the feasibility or otherwise of a single trading product at Wallumbilla, while considering the most appropriate model to recommend to the Energy Council for consideration at its December 2015 meeting.[443]

The Wallumbilla GSH does not currently offer the types of hub services (eg balancing, storage, compression and redirection), offered at some other international hubs that can support trading and liquidity. Consolidation of delivery locations at Wallumbilla would require hub services to connect delivery points and facilitate trade in a single market.

Key hub services include:[444]

- intra-hub transfer service: transfer of gas from one interconnected pipeline to another through a hub, which may include re-direction and/or compression services;
- title transfer service: a permanent transfer of ownership of gas from one party to another at the same location (for example in-pipe trades);
- balancing service: to manage shipper shortfalls or a pipeline mismatch (could have multiple providers); and
- storage service: facilitates the storage (or withdrawal) of gas in a connected storage facility for use at another time.

The development of standard products for the secondary trading of capacity by industry could, in the future, allow transportation and hub services to be listed as trading products on the exchange.

Stakeholder submissions to the Discussion Paper and Stage 1 Draft Report

Stakeholders were generally positive about the voluntary Wallumbilla GSH in submissions, although many noted the detrimental impact on liquidity at the Brisbane STTM since the GSH became operational. Due to the consistency of views from stakeholders through the Stage 1 process, submissions received to the Discussion Paper and draft report are summarised below.

442 ibid.

443 AEMO, *Wallumbilla Single Product, High Level Design Report*, June 2015, p. 2.

444 AEMO, *Wallumbilla Single Product, High Level Design Report*, June 2015, p. 13.

Stakeholders were generally supportive of further development of the Wallumbilla GSH

The majority of parties that commented on the further development of the Wallumbilla GSH were supportive of AEMO's workstream to establish a single trading zone and a more robust reference price. In this context, GDFSAE and QGC note that in order to support the development of financial risk management products an efficient reference price must first be established.[445]

However, CQ Partners commented that considerable cost and effort is being put into trying to improve the Wallumbilla GSH and that, in their view, there is unlikely to be a positive net benefit. CQ Partners also expressed concern that the general focus of the AEMC's Stage 1 Draft Report is to change the design of the STTM and DWGM - two markets that are working efficiently - to bring them in line with the one market that, in their opinion, is not working - the Wallumbilla GSH. CQ Partners also note the lack of transparency around how AEMO is recovering GSH costs and suggested the market may be running at a significant loss.[446]

AGL held the view that, while the lack of physical interconnection at Wallumbilla may limit any expansion in trade, its strong view is that "markets need to be encouraged and allowed to develop organically rather than be foisted on the industry". In this respect, AGL would like to see more initiatives and innovation associated with a low-cost, voluntary bilateral trading arrangement.[447]

Parties held mixed views on the appropriate provision of hub services and the potential need for economic regulation. APA Group does not believe that economic regulation of hub services is necessary and refers to a model it has previously proposed, commenting that the models proposed by AEMO will involve significant costs that are not proportionate to the size of the market.[448]

Santos warns against premature conclusions about the need for economic regulation for the provision of hub services.[449] The ESAA also has reservations in this regard, noting that it is important to consider how market participation and liquidity can be enhanced over time, but any consideration of economic regulation should ultimately be informed by an assessment of overall costs and benefits and have regard to existing rights.[450]

Origin and Stanwell consider there is merit in investigating the effects on the competitive landscape for the provision of hub services, including the need for

445 GDFSAE, Stage 1 Draft Report submission, p. 6; QGC, Stage 1 Draft Report submission, pp. 4-5.

446 CQ Partners, Stage 1 Draft Report submission, p. 6.

447 AGL, Discussion Paper submission, p. 3.

448 APA, Stage 1 Draft Report submission, pp. 2-3.

449 Santos, Stage 1 Draft Report submission, p. 5.

450 ESAA, Stage 1 Draft Report submission, p. 6.

economic regulation.[451] AGL states that it does not support a model where APA is made the hub operator, given its position as a monopoly provider.[452]

The view expressed by ERM Power differed to those parties above. ERM notes that a shipper who does not have contractual access to a particular trading location at Wallumbilla can already secure redirection services from the transmission operator to obtain access. ERM noted that it would be concerned if a single trading zone model effectively forces participants to pay for a suite of mandatory additional services they would not normally have purchased.[453]

APGA suggested that concerns raised by participants around their ability to take advantage of Wallumbilla stem from their desire to access Wallumbilla on the same or better terms than those who have underwritten the infrastructure investment.[454]

Impact on liquidity in the Brisbane STTM

A number of parties submitted that the Wallumbilla GSH has impacted liquidity on the STTM. In particular:

- Santos observed some change in behaviours with participants waiting for the STTM scheduling at 2.00pm before executing genuine trades via the Wallumbilla GSH. In most instances, it is assumed participants are looking for gas delivered into Brisbane and are testing whether there is sufficient liquidity at the STTM to support this.[455]
- Stanwell considered that limitations on systems and participant supply and demand withdrawal points have created barriers to trade at Wallumbilla, although "in pipe" trades have reduced this – at a cost. Stanwell noted that ideally one market would operate in each region to maximise liquidity, and that the Brisbane STTM is reducing liquidity at Wallumbilla as participants can offer or bid at Wallumbilla knowing the STTM is available at a last resort.[456]
- Arrow Energy stated trading at RBP can impact trading on the STTM and vice versa. Arrow considers that where before clearing prices could be impacted by the relatively small STTM volumes, the Wallumbilla GSH now offers a more liquid and transparent alternative as a reference.[457]

Lumo Energy was of a different view and stated that trading at the GSH has not had a significant impact on trading and liquidity on other facilitated markets.[458]

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451 Origin, Stage 1 Draft Report submission, p. 5; and Stanwell, Stage 1 Draft Report submission, p. 2.

452 AGL, Stage 1 Draft Report submission, p. 4.

453 ERM Power, Discussion Paper submission, pp. 9-10.

454 Australian Pipelines and Gas Association, Discussion Paper submission, p. 34.

455 Santos, Discussion Paper submission, p. 5.

456 Stanwell, Discussion Paper submission, p. 9.

457 Arrow Energy, Discussion Paper submission, p. 9.

458 Lumo Energy, Discussion Paper submission, p. 10.

7.2.2 Development of a GSH at Moomba

AEMO has been investigating the establishment of another trading location at Moomba as part of its current GSH work. Specifically, AEMO has been undertaking a project to determine:

- the level of support within industry for another GSH at Moomba;
- where the Moomba hub should be defined, ie physical points or a virtual point; and
- how a Moomba hub would affect trading at the Wallumbilla supply hub (eg liquidity).

Whether or not the establishment of a trading location at Moomba would reduce liquidity at Wallumbilla is a key issue for market participants, as detailed in submissions below.

Since publication of the AEMC's Stage 1 Draft Report, AEMO has provided a high level design report to the Energy Council recommending the implementation of another GSH at Moomba. The AEMC understands that the Energy Council is to consider this proposal as part of its July 2015 meeting.

The AEMO high level design report proposes to implement the following two trading locations at Moomba:[459]

- Moomba Sydney Pipeline (MSP) location; and
- Moomba Adelaide Pipeline System (MAPS) location.

AEMO proposes that the same suite of products will be on offer at Moomba as at Wallumbilla (balance-of-day, day-ahead, daily, weekly and monthly products) as well as a spread product to encourage trading between the two hubs. AEMO state that while spread products do not provide a substitute for an effective capacity trading mechanism, they could enhance the liquidity of the Wallumbilla and Moomba markets and encourage a trade in secondary capacity.[460]

AEMO has estimated that its total cost to implement two additional Moomba trading locations within the GSH would be less than $200,000 and that this cost would primarily be for the internal IT development and market readiness activities to ensure that participants are sufficiently prepared to trade.[461]

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459 AEMO, *Moomba Trading Location*, High Level Design Report, May 2015, p. 3.

460 ibid.

461 AEMO, *Moomba Trading Location*, High Level Design Report, May 2015, p. 4.

Stakeholder submissions to the Discussion Paper and Stage 1 Draft Report

Stakeholders that commented on the proposed Moomba GSH were generally supportive of its development, although the majority of these parties consider that it should be included as part of the development of a longer-term strategy for the east coast gas market.[462] Most parties that did not mention the establishment of a Moomba hub explicitly were supportive of a strategy to identify the optimal number, type and location of facilitated markets.[463]

AEMO notes that it has submitted a draft high level design for a Moomba trading location to the Energy Council for consideration at the July 2015 meeting. AEMO supports the implementation of a new trading hub at Moomba and considers that any reduced liquidity at Wallumbilla from implementing Moomba is unlikely to be material.[464]

Orora is supportive of establishing a Moomba GSH and suggests that pipeline capacity constraints on the QSN link mean that if large users in South Australia, New South Wales or Victoria procured gas at Wallumbilla, it could not be physically delivered to Moomba.[465] The EUAA also stated support for the development of the Moomba GSH to serve large gas users and help circumvent physical constraints on the QSN link.[466]

EnergyAustralia also notes that the GSH model may require further development depending on the outcomes of Stage 2, but that any resultant model refinement can occur after implementation (similar to the post-implementation move to a single product at Wallumbilla).[467]

In contrast to the majority view, QGC argues that, while a Moomba hub may appear a simple, logical and appropriate response to increasing participants' supply options, it does change the nature of the market. Based on past experience, QGC notes that, given the limited size of the east coast market, there is significant benefit in concentrating liquidity at a single point (Wallumbilla), as this will provide sufficient depth to enable the establishment of an efficient reference price. Without an efficient reference price, QGC argues that the ASX gas futures contracts will not be successful.[468]

Alinta considers that the creation of additional hubs is a second best option for market development that requires further consideration. While Alinta acknowledges that a

462 Santos, Stage 1 Draft Report submission, p. 5; GDFSAE, Stage 1 Draft Report submission, p. 6; APA, Stage 1 Draft Report submission, p. 17; Alinta, Stage 1 Draft Report submission, p. 3; AGL, Stage 1 Draft Report submission, p. 4; and ESAA, Stage 1 Draft Report submission, p. 5.

463 Origin Energy, Stage 1 Draft Report submission, p. 5; ERAA, Stage 1 Draft Report submission, p. 1; Stanwell, Stage 1 Draft Report submission, p. 1; Jemena, Stage 1 Draft Report submission, p. 3; and Hydro Tasmania, Stage 1 Draft Report submission, p. 2.

464 AEMO, Stage 1 Draft Report submission, p. 6.

465 Orora, Stage 1 Draft Report submission, p. 2.

466 EUAA, Stage 1 Draft Report submission, p. 5.

467 EnergyAustralia, Stage 1 Draft Report submission, p. 8.

468 QGC, Stage 1 Draft Report submission, p. 6.

Moomba hub would provide participants with an ability to buy gas that could be used to support market entry in Sydney or Adelaide, there is a question around whether another hub is required at all if existing transport costs were not so excessive.[469]

With respect to another hub at Moomba, Stanwell argues this would reduce liquidity at Wallumbilla and that it would be better to design market arrangements to improve liquidity at Wallumbilla; or develop a virtual hub between Wallumbilla and Moomba.[470]

7.3 AEMC's Stage 1 findings and recommendations

This section sets out the Commission's findings from this aspect of the review, as well as detailing the type of work the Commission will undertake on the GSH for Stage 2. A Stage 1 recommendation to harmonise gas day start times is also outlined, consistent with the STTM and DWGM chapters.

7.3.1 Final Stage 1 findings

While only being operational for around 16 months, market participants are generally of the view that the Wallumbilla GSH provides a simple and low cost platform for the commodity trading of gas. However, we note that participants can avoid using the market if they choose and only face transaction costs if trades are completed. Anecdotal evidence also suggests that some participants are using the Wallumbilla GSH to trade small volumes of gas in order to find a counterparty, before completing the bulk of the transaction outside of the market.

Of particular interest to the Commission is the apparent reduction in volumes traded through 2015 to date and the subsequent increase in price volatility shown in Figure 7.2, which could indicate the lack of depth in the market. While the GSH is still very much in its infancy, with only a relatively small volume of trades occurring at the hub, the Commission notes that trading at the hub appears to be becoming more sporadic in terms of both volume and price.

As the Wallumbilla GSH matures, there will naturally be refinements to the initial market design that need to be made consistent with any fledging market. This has been evidenced in both the incremental development of the STTM and DWGM since their respective market-starts. An example of this applying to the GSH can be seen by the desire to consolidate the current market into a single location design in order to increase trading opportunities and liquidity.

While most participants are generally supportive of expanding the current voluntary, low cost GSH model to a Moomba location, a key theme coming through in submissions is that the implementation of additional trading hubs should be included as part of the development of a longer-term strategy for the east coast gas market.

469 Alinta Energy, Discussion Paper submission, p. 6.

470 Stanwell, Discussion Paper submission, p. 6.

7.3.2 Final Stage 1 recommendation

As discussed in detail in section 5.3.3, the Commission recommends the Energy Council propose a rule change request to set gas day start times for all facilitated markets to 6.00am, in line with the DWGM.

The gas day start time for the GSH is not specified within the NGR, but instead in the exchange agreement administered by AEMO. As such, we are recommending that, as part of the rule change proposal, the Energy Council requests the AEMC define the gas day start time for the GSH in the NGR as 6.00am. Consequential changes to the exchange agreement are likely to be required to implement this change.

Codifying the gas day start time for the GSH in the NGR provides certainty for participants that all facilitated markets on the east coast will have the same start time. This is important not only for the existing east coast facilitated markets but also in light of any recommendations stemming from the long-term strategy to be developed as part of Stage 2 for how gas trading on the east coast could evolve. It also ensures that the start time for all markets on the east coast is governed by one legislative framework (the NGR), minimising the number of mechanisms required to be changed and associated industry consultation to accommodate any future amendments that could relate to gas day start times.

The AEMC will work closely with AEMO as part of the rule change process to ensure implementation of this recommendation minimising disruption to industry.

7.3.3 Stage 2 direction

As part of Stage 2 of this review, the Commission will look to complement AEMO's Wallumbilla GSH workstream by considering the potential for workably competitive outcomes to emerge in hub services at Wallumbilla, including the potential need for economic regulation and whether this would be possible under the current regulatory framework set out in the NGL and NGR.

We note that AEMO is expected to recommend its preferred approach for a single trading location at Wallumbilla, and how this could be implemented, to Ministers at the Energy Council meeting in December 2015.

More broadly, we see it as prudent to consider the role of the Wallumbilla (and potentially Moomba) GSH within the broader east coast gas market as part of Stage 2. This work will look at the role of the GSH on the east coast going forward, how it is likely to interact with other facilitated markets, and potential future development opportunities additional to the work currently being carried out by AEMO on behalf of the Energy Council.

8 Information Provision

Box 8.1 Summary of findings and recommendations

Gas, transportation and risk management services in the east coast gas market have historically been sold under medium- to long-term bilateral contracts. The prices and other terms and conditions struck under these agreements have invariably been treated as confidential by the parties and so too has information on some other key demand and supply fundamentals.

While some steps have been taken to reduce informational barriers, there are still 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. We have therefore made recommendations that aim to contribute to the price discovery process and enable more informed and efficient decision making.

Our Stage 1 recommendations can be implemented over the next 6-12 months. The AEMC will:

- work with the ABS to develop a survey-based gas price index that will measure the trends in the prices payable under bilateral contracts over time; and
- address some of the clear informational gaps in the Bulletin Board through the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change.

Our Stage 2 directions are likely to require more fundamental changes to the reporting and/or enforcement framework. We therefore intend to establish a technical working group to assist with our strategic review of gas market information needs, particularly the development of the Bulletin Board. This will consider issues including:

- enhancing the role of the Bulletin Board as the central repository of key market data relevant for commercial decision making;
- opportunities to improve the coverage and content, timeliness, accuracy and usability of the information provided to the market through the Bulletin Board, and whether the benefits of any informational improvements are likely to exceed the costs; and
- broader institutional issues, including the governance framework for long-term oversight and day-to-day management of the Bulletin Board, as well as compliance and enforcement processes.

The findings of the strategic review will be incorporated into our Stage 2 Final Report.

8.1 Background

An important characteristic of a competitive market is that all participants have ready access to the information they require to make informed and efficient decisions about consumption, production, transportation, investment and risk management in both the short- and long-run (see Box 8.2). 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.

Box 8.2 The economics of information

In a workably competitive market, the prices generated by the interaction of buyers and sellers can provide a useful indication of expectations about supply and demand, and a signal to efficiently allocate resources. If prices are struck in an open and transparent market then other market participants may be able to rely on the signals provided by these prices rather than having to carry out their own detailed analysis of market conditions and prices.

Markets are dynamic and participants are not always rational or able to foresee future events. This is a natural state of any market and not necessarily a market failure. Participants in workably competitive markets can produce solutions to informational shortages, although there may be some instances where government intervention is required to improve information availability.

Information may have the characteristics of a public good – non-rivalry and non-excludability.[471] Other information may be private, which is excludable to others. This is a source of information asymmetry, the situation where a party to a transaction has greater information than the other. This can occur before or after a contract is entered into. Another source of information asymmetry is the cost of information, leading market participants to economise on, and seek efficient levels of, information.

Information asymmetry is an issue because it can lead to inefficient trade and contracting; decisions made on incorrect information can lead to price divergence and inefficient resource allocation, because parties will not have been able to take into account the actual state of the market. Information asymmetry can also arise in regulation because regulators and policy makers tend not to have as much information as the participants they are regulating.

The east coast gas market has historically operated in quite an opaque manner with gas, transportation and other risk management services sold under highly customised medium- to long-term bilateral contracts. The prices and other terms and conditions struck under these agreements have invariably been treated as confidential by the parties and so too has information on some other key demand and supply

471 Non-rivalry involves a situation where one person’s consumption does not diminish another’s ability to consume the good or service. Non-excludability is the prohibitively high cost of excluding a person from using or consuming a good or service.

fundamentals. The lack of transparency in the market, coupled with the fact that contracts tend to be highly customised, means that the price discovery process can involve lengthy bilateral negotiations and may be afflicted by informational deficiencies and asymmetries.

Although some steps have been taken to reduce informational barriers in this market, there are still some significant informational gaps and asymmetries, which are becoming more apparent as market participants try to adjust to the changes underway in the market. There are also growing calls from market participants and the Energy Council[472] for the market to become more transparent and for improvements to be made to the coverage, accuracy and timeliness of the information made available to the market. Further detail on the factors that are driving the need for more information in the market is provided below along with an overview of the alternative roles that governments and industry can play in producing and disseminating information.

What is driving the need for more information in the market?

There are three broad factors that appear to be driving the need for further information in the east coast gas market at present.

First, the Australian economy is undergoing rapid structural change. Australia's cost base and natural resource endowment has led to a shift away from manufacturing and gas-fired electricity generation towards commodity extraction and export. In this environment, decisions are being made that will have long-term resource allocation implications. While this is a normal process for an economy, it is a particularly relevant issue now given the extent and pace of change and the uncertainty currently surrounding gas prices and the availability of supply. Uncertainty is particularly relevant at present because a large number of long-term GSAs are due to expire in the next one to two years, and decisions will be made on available information that will affect resource allocation for years to come.

Some large users have reportedly found it difficult to find producers that are willing to enter into new long-term contracts, or contracts of sufficient length to meet their commercial needs and support investment.[473] Concerns have also been raised by some users about the prices payable under new contracts.[474] There are also reports of some producers offering less flexibility in GSAs to manage variations in demand, which, given heightened uncertainty, may result in greater demand for other risk mechanisms (eg storage and the facilitated markets).

These changes are reportedly prompting some large users to consider whether to re-contract. While this issue is inherent in any structural change process, it appears to be exacerbated by the prevailing uncertainty in the market.

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472 COAG Energy Council Vision, December 2014, p. 4.

473 See, for example: Alliance of Industry Associations, Discussion Paper submission, 2015, p. 6. Department of Energy and Water Supply, *Gas Market Review Queensland*, 2012, p. 38 and *The Australian*, 'Clash looms as supply contracts unsecured,' 19 January 2013.

474 Alliance of Industry Associations, Discussion Paper submission, p. 6.

In this environment, greater information may be required to facilitate the rapid and substantial shift in resource allocation, and to enable participants to make informed and efficient long-term decisions about gas consumption, production, transportation and investment. If this does not occur, it could result in an inefficient allocation of resources.

Second, the demand for gas will soon be more concentrated than it has been in the past, with LNG producers to account for a substantial proportion of consumption. When coupled with the fact that CSG is accounting for a greater proportion of supply, the market is becoming more sensitive to changes in:

- the actions of LNG producers, both in terms of their demand for gas and their supply of gas into the domestic market; and
- technical limitations that may limit the rate at which gas production from CSG sources can be changed in response to demand fluctuations.

Short-term allocation decisions are therefore becoming a more significant issue in the market, requiring information on market changes in a more timely and accurate manner than has been provided in the past, and mechanisms to manage them efficiently. This change is also driving calls for improved information on CSG production, deliverability risks and the activities of LNG producers.

Third, with larger volumes of gas being produced and consumed, there is an increasing demand from some participants for more diverse products and mechanisms to trade and transport gas and manage risk. In this environment, better quality information, more extensive coverage of information and more useful price signals are likely to be required to coordinate a larger, and more liquid and diverse market. Greater transparency is also likely to be required to support the development of new products and mechanisms to trade and transport gas and manage risk.

While these observations suggest that the market may not currently have the information required to efficiently allocate gas, regulatory intervention to require greater transparency should only occur if it can be demonstrated that there is a clear market failure. This issue is discussed in further detail below.

Institutional considerations in information provision

Given the importance of information in a well-functioning market, and the difficulties in producing and disseminating it, it is worth considering the various means of doing so. Both market- and government-based methods can be effective in improving the amount of information available to market participants and the choice between these two will depend on the extent to which there is a market failure,[475] the opportunities for entrepreneurial solutions, and the potential for unintended consequences from government intervention.

475 The term "market failure" is used in this context to refer to a situation in which the market, left to its own devices, is unable to allocate resources efficiently.

Government intervention may occur where there are informational deficiencies or asymmetries that cannot be corrected by the market. This may be due to market power, limited commercial incentive to make available sensitive information, or the cost involved. Government intervention may take a number of different forms. For example, market participants may be required by a legislative instrument to provide certain information to the market, government may provide the information itself, or it may establish a mechanism to improve information provision. Like any market failure, government intervention should only occur if the benefits of the intervention are likely to outweigh the costs.

Private organisations can also play a role in providing information to the market, or even requiring information to be provided to the market (eg the ASX requires continuous disclosure of market sensitive information as a necessary condition for an exchange listing). Examples of private providers of information in the east coast gas market include EnergyQuest's EnergyQuarterly and the Argus LNG Daily market report.

Other recent developments in private information provision have involved platforms that match buyers and sellers of certain products. This business model involves the use of a platform to bring together market participants and information, and in so doing reducing transaction costs and enabling previously uneconomic trades to occur.[476] The platform operator receives a portion of the value created in the trade. Examples of these types of platform businesses include eBay, Uber and airbnb.

As this brief discussion highlights, there are various ways in which relevant and useful information can be brought into a market for use by participants. When considering the role that government should play with respect to information provision in the east coast gas market, key considerations include:

- the extent to which the incentives for private sector provision may be limited due to the information being a public good; and
- whether the government may need to require the private sector to provide information due to there being strategic reasons for the private sector not to disclose information but potential for anti-competitive outcomes.

Finally, in considering the role of government, it is also necessary to consider the level or coverage of information that the government may wish to provide or require. While it may seem apparent that more information should be preferred to less, this may not always be the case. Careful consideration must therefore be given to the level of information required by the market.

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476 In bringing together both sides to a trade that were previously not connected, information on willingness to buy and sell is revealed and trade is enabled. Information is also generated by requirements imposed by the market operator, such as information provision as a condition for entering the market, and feedback as to the performance of both parties to the contract. Therefore, screening and reputation overcomes information problems associated with pre- and post-contract behaviour, thereby enabling trust and further trade to occur. Therefore, platforms may substantially reduce information problems.

Matters considered in the chapter

Given the matters outlined above, it is relevant to consider whether improvements can be made to the coverage, timeliness and accuracy of market-based information to:

- simplify the price discovery process and enable more informed and efficient decision making and risk management to occur; and
- facilitate the development of a more liquid wholesale gas market, an efficient reference price and risk management products over the longer term.

These matters are explored in further detail in this chapter, which is structured as follows:

- section 8.2 sets out the information currently available to market participants, the observations that stakeholders and recent reviews have made about this information and the steps that have recently been taken to try and improve the National Gas Bulletin Board (Bulletin Board); and
- section 8.3 considers sets out our Stage 1 recommendations and Stage 2 direction for improvements that can be made to the current arrangements to improve the efficiency with which decisions are made.

8.2 Information currently available in the market

A number of steps have been taken by policy makers and market participants over the last ten years to increase the level of transparency in the east coast gas market and enable more informed decisions to be made about the consumption, production and transportation of gas and longer-term investments.[477] Notwithstanding the developments that have occurred in this area, concerns have been raised by a number of parties about:

- the lack of transparency surrounding wholesale gas prices, transportation costs and other risk management services; and
- the fragmented and incomplete nature of the information currently available to the market.

Similar concerns were also expressed in the Energy Council's Vision, which noted the need for more 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.[478] Further detail on the concerns that have been raised is provided below, along with a brief overview of the information currently available to market participants.

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477 These steps include, amongst others, the development of the National Gas Bulletin Board in mid-2008, the introduction of the Gas Statement of Opportunities in 2009 and the introduction of capacity listing services by some pipeline owners.

478 COAG Energy Council Vision, December 2014, p. 4.

8.2.1 Existing informational resources

The resources that market participants can currently have recourse to when making consumption, production, transportation, risk management and investment decisions include:

- The National Gas Services Bulletin Board (Bulletin Board), which is administered by AEMO and contains information on the standing capacity, short- and medium-term capacity outlook and utilisation of designated production facilities, storage facilities and transmission pipelines in eastern Australia. It also contains a listing service for transmission capacity and gas (see Box 8.3 for further detail on the Bulletin Board).
- The Gas Statement of Opportunities (GSOO) and National Gas Forecasting Report, which are prepared by AEMO on an annual basis and contain consumption forecasts, reserve estimates, production and transmission cost estimates, storage, processing and transmission information and a supply adequacy assessment.
- AEMO's website, which contains pricing and other market based information from the Wallumbilla Supply Hub, the DWGM and STTM.
- The AER's publications, which include:
  - a Weekly Gas Market Report, which contains information on activity in the Wallumbilla Supply Hub, DWGM and STTM, production and pipeline flows and gas fired generation; and
  - regulatory decisions for pipelines that are subject to full regulation.
- State and Australian government reports on gas resources and major projects (eg the Australian Department of Industry and Science publishes Resources and Energy Quarterly, Resources and Energy Statistics, and Australian Energy Projections).[479]
- Industry publications, such as EnergyQuest's EnergyQuarterly, which contains information on exploration, production, consumption, wholesale gas prices, the LNG projects, gas-fired generation, storage and transmission pipelines.
- Market participants' websites (eg producers' and pipeline owners' websites and the capacity trading websites that have been set up by APA and Jemena).
- Annual reports and other periodic disclosures for ASX-listed entities (eg price-sensitive information and periodic disclosure of production, development and exploration activities for mining, oil and gas producing entities).

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479 A list of the Department of Industry and Science's publications can be found here: http://www.industry.gov.au/industry/Office-of-the-Chief-Economist/Publications/Pages/default.aspx#

- Information that is discovered or revealed during bilateral contract negotiations.

Box 8.3 Bulletin Board

The Bulletin Board was established in July 2008 following a recommendation by the Gas Market Leaders Group (GMLG) that a web-based electronic communications system be developed to provide market participants and observers (including governments) with ready access to up-to-date information on the demand-supply outlook for key production facilities, storage facilities and transmission pipelines in eastern Australia.[480]

The regulatory arrangements applying to the Bulletin Board are set out in Chapter 7 of the NGL and Part 18 of the NGR. Unlike the access regulation provisions, which only apply to covered pipelines, these provisions apply to a broader group of transmission pipelines, production and storage facilities in eastern Australia.

The Bulletin Board provisions in the NGL and NGR require AEMO to operate and maintain the Bulletin Board and notify the AER of any breaches of this part of the NGR. They also allow AEMO to:

- develop procedures that, among other things, specify the way information is to be provided, published and maintained on the Bulletin Board and to define demand and production zones; and
- declare that a transmission pipeline, gas storage facility or production facility become a Bulletin Board facility if it is not subject to an exemption declaration.

If a pipeline, storage or production facility is declared a Bulletin Board facility, it is required by rules 163-174 of the NGR to provide AEMO with information on, amongst other things, the standing capacity of the facility, the facility's short-term (7-day) and medium-term (12 month) capacity outlook and the daily utilisation of the facility. Bulletin Board pipelines are also required to provide aggregated information on pipeline nominations and forecast deliveries by zone and a 3-day linepack capacity adequacy outlook flag. Further detail on the information Bulletin Board facility operators are required to provide AEMO under the NGR is set out in Figure 8.1.

The Bulletin Board provisions also allow registered participants to notify other users if they have gas or spare capacity to sell.

The costs that AEMO incurs in operating and maintaining the Bulletin Board are recovered from shippers that utilise the Bulletin Board pipelines through a fee that reflects the shipper's share of the volume of gas transported in the relevant period (rule 191).

480 Gas Market Leaders Group, *National Gas Market Development Plan*, June 2006, p. 4.

Figure 8.1 Information coverage

	Upstream			Transmission Pipelines			Distribution	Storage Facilities		STTM and DWGM	Demand
	Resources and Reserves	**Production** (capacity, production, outlook)	**Wholesale Gas Prices**	**Pipeline** (capacity, utilisation, outlook)	**Secondary capacity**	**Transport Costs**	**Transport Costs**	**Storage** (capacity, utilisation, outlook)	**Storage costs**	**Prices, injection and withdrawal**	**Current and outlook**
Bulletin Board	×	BB facilities only	×	BB facilities only	Listing service	×	×	BB facilities only	×	×	×
GSOO	✓		×	✓	×	Estimates for some pipelines	×	✓	×	×	Historic and forecast
AEMO's website/trading platforms	×	×	Wallumbilla Gas Supply Hub information	×	×	×	×	×	×	✓	×
AER reports	×	×		×	×	For regulated pipelines	For regulated pipelines	×	×	✓	×
Government reports	✓	×	×	×	×	×	×	×	×	×	Historic estimates
EnergyQuest	✓		Estimates	✓	×	Estimates for some pipelines	×	✓	×	×	Historic estimates
Market participants' websites	Some producers' websites		×	Some pipeline owners' websites	APA's and Jemena's capacity trading websites	Some pipeline owners' websites	✓	Some websites	×	×	×
Annual reports and other public announcements	Some producers' annual reports and production and reserves reports		Media releases (if ASX listing)	×	×	×	×	✓	×	×	×

8.2.2 Recent informational improvements and changes underway

Over the last 18 months a number of steps have been taken to:

- Improve the functionality and usability of the Bulletin Board – AEMO commenced work on this project in 2014 and the first phase of the redevelopment, which included redesigning the Bulletin Board interface and developing a capacity listing service, was completed in late 2014.[481]
- Improve the quality of some of the information reported on the Bulletin Board – over the last year the AER has worked with CSG producers to improve the quality of the information they provide to the Bulletin Board.[482]
- Address some of the informational gaps on the Bulletin Board – in May 2014, the AEMC made a rule to amend the NGR to increase the level of short- and medium-term capacity outlook information to be published on the Bulletin Board.[483] The AEMC also recently made a rule to remove the requirement in the NGR for an emergency information page on the Bulletin Board.[484]
- Improve the quality of planning and investment related information – in 2014 AEMO published its first National Gas Forecasting Report and has also made a number of improvements to the GSOO.

The Energy Council has also undertaken a significant amount of work to determine what information is likely to be required to facilitate a greater degree of capacity trading amongst shippers and has recently submitted the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change to the AEMC. As the following statement from the Energy Council highlights, the scope of the proposed rule change extends beyond just facilitating secondary capacity trading:[485]

> "In preparing this proposal, officials have also identified other rule changes relating to the provision of gas pipeline flow and facility data that will: improve the operational management of facilitated wholesale gas markets; better inform the development of AEMO's *Gas Statement of Opportunities* (GSOO); and enable a more accurate understanding of gas flows in Australia's east coast gas market and in turn allow a better representation of gas flows to be published on the Bulletin Board."

The additional information that Bulletin Board facility operators would be required to provide under the rule change is set out in the shaded cells in Table 8.1.

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481 AEMO, *Gas Bulletin Board Draft Budget: 2015-16*, March 2015. The second phase of the re-development is expected to involve improving the upload and validation functionality while the third phase is expected to involve incorporating any new data arising from the rule change.

482 AER, Discussion Paper submission, p. 3.

483 AEMC, *Final Rule Determination – National Gas Amendment (National Gas Bulletin Board Capacity Outlooks) Rule 2014*, 1 May 2014.

484 AEMC, *National Gas Amendment (Removal of Gas Bulletin Board emergency information page) Rule 2015*, 23 April 2015.

485 COAG Energy Council, *National Gas Rule Change Request and Proposal – Gas Transmission Pipeline Capacity Trading: Enhanced Information*, 30 March 2015, p. 3.

Table 8.1 Existing and proposed information in Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change

Information to be provided to AEMO		Frequency
Bulletin Board Transmission Pipeline Operators		
Existing information requirements	Name plate capacity rating	Annual*
	7-day capacity outlook (short-term)	Daily
	Medium-term capacity outlook (utilising maintenance reports provided by facility operators or shippers)	As issued
	Actual pipeline gas delivery information for each demand and production zone for the previous day	Daily
	Aggregated delivery nominations by zone and aggregated forecast deliveries by zone for subsequent gas days	Daily
	3-day linepack capacity adequacy outlook flag	Daily
	Contact details	Daily
Uncontracted capacity	3-year outlook for uncontracted (available) primary capacity	Monthly
	List of shippers with contracts and contact details in the relative order of their contracted capacity	Monthly
Secondary capacity trade	Data from secondary capacity trading platforms	Week-after basis
Detailed facility data	Location of receipt and delivery points, production, storage and transmission pipelines to the pipeline connects, name plate rating for each gate station and delivery points that constitute gate stations	As applicable
Flow data by point	Aggregated receipt/delivery point flow data by zone	Day-after basis
	Disaggregated receipt/delivery point flow data (confidential)	Monthly
Bulletin Board Storage Provider		
Existing information requirements	Name plate capacity rating	Annual*
	7-day capacity outlook (short-term)	Daily
	Medium-term capacity outlook (utilising maintenance reports provided by facility operators to shippers)	As issued
	Actual storage production data for each gas day	Daily
	Contact details	Daily
Detailed facility data	Identification of all the Bulletin Board pipeline, receipt and delivery points connected to the storage facility	As applicable
Bulletin Board Production Facility Operators		
Existing information requirements	Name plate capacity rating	Annual*
	7-day capacity outlook (short-term)	Daily
	Medium-term capacity outlook (utilising maintenance reports provided by facility operators to shippers)	As issued
	Actual production data for each gas day	Daily
	Contact details	Daily
Detailed facility data	Identification of all the Bulletin Board pipelines, receipt and delivery points connected to the production facility.	As applicable

*If the capacity rating changes, the facility operator must notify AEMO as soon as possible.

Note: shaded areas indicate information proposed in the rule change request.

A further development that is currently being considered by AEMO is whether the Bulletin Board procedures should be amended to include a new demand zone at Curtis Island. If this change is made to the procedures it will result in:

- QCLNG, GLNG and APLNG pipelines and any production or storage facilities that inject gas directly or indirectly into these pipelines becoming Bulletin Board facilities; and
- each facility being required to provide the information specified in the NGR once GLNG's project commences in late-2015.

The ACCC's inquiry into the competitiveness of wholesale gas prices and the structure of processing, transportation, storage and marketing segments of the gas industry, announced on 5 April 2015, will examine information transparency and transaction costs, including gas supply contractual terms and conditions.[486]

As this brief summary highlights, a number of the improvements that have been suggested in earlier reviews and by stakeholders have already been addressed, or are in the process of being considered either as part of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change or AEMO's Bulletin Board procedure change.[487] There are, however, a number of suggested improvements that have not yet been addressed, such as:

- increasing the level of transparency around wholesale gas prices, transportation costs and other risk management services;
- reducing the degree of information fragmentation, continuing to improve the usability and functionality of the Bulletin Board and improving the accuracy, timeliness and general compliance of the information provided by Bulletin Board facilities;
- including more detailed information on storage and the medium-term capacity outlook on the Bulletin Board;
- expanding the coverage of the Bulletin Board to include large end-users and other more fundamental changes to the reporting and enforcement framework; and
- improving the emergency arrangements.

These suggestions are considered in further detail in section 8.3.1.

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

487 For example, the ERM Power, Alinta and AER suggestion that information on the LNG producers' activities be reflected on the Bulletin Board.

8.2.3 Observations from previous reviews

A number of the reviews carried out in the last two years identified shortcomings with information provision in the east coast gas market and made some recommendations on how these shortcomings could be addressed.

For example, in the Scoping Study consultation process, concerns were raised by a number of stakeholders about:[488]

- the level of information available on the Bulletin Board;
- the fact that some storage facilities in Queensland were not Bulletin Board facilities;
- the quality and accessibility of the existing STTM, DWGM and Bulletin Board data; and
- the lack of transparency surrounding transportation costs on some pipelines.

The Eastern Australian Domestic Gas Market Study also expressed concerns about the adequacy of the information available to the market to support the price discovery process and enable informed decisions to be made, and the following matters:[489]

- the lack of transparency surrounding wholesale gas prices, which the study noted may render some participants unable to negotiate confidently on price and could also hinder the development of forward markets and risk management products;
- the availability of information on CSG developments and delivery risks;
- the limited information on processing and storage capacity, utilisation of transmission pipelines, capacity trading activity and transmission costs; and
- the quality of information available for planning and investment decisions.

To address these concerns, the study recommended that further reform be carried out in this area, in consultation with industry, and focus on “improving price discovery in the wholesale market, including mechanisms to provide increased visibility on key market drivers".[490] The study also recommended specific improvements to the Bulletin Board and GSOO and encouraged industry to progress the development of a gas price index.[491]

488 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 128.

489 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, pp. 15-16, 64 and 90.

490 ibid, p. 89.

491 ibid, p. 90.

Similar recommendations were also made by the Victorian Gas Market Taskforce, who noted that the level and quality of information in the market could be improved by:[492]

- accelerating industry-led efforts to develop a survey based forward gas price index to report price expectations;
- publishing available transmission capacity on the Bulletin Board; and
- including a comprehensive annual forecast of reserves, gas supply, industrial and residential demand and supply and transportation asset capacity in the GSOO.

8.2.4 Stakeholder submissions to Discussion Paper

Submissions on information provision made to us in response to the Discussion Paper for this review primarily focussed on the adequacy of existing information and where improvements could be made. Some stakeholders also commented on emergency arrangements currently in place. An overview of the views expressed by stakeholders on these issues is provided below.

Adequacy of existing information

A common theme to emerge from submissions to the Discussion Paper is that there is insufficient information in the market at present to enable participants to make informed and timely decisions on consumption, production, transportation, investment and risk management, and that change is required.

This view was clearly articulated by GDF Suez Australian Energy (GDFSAE), who suggested that at present "information arrangements are fragmented across multiple platforms and are incomplete which creates concerns for market participants, especially those not across the breadth of the supply chain, and interested stakeholders". GDFSAE highlighted that "information is critical to enable participants to make decisions on how to respond to and manage risk", as "information asymmetries are genuine impediments to fully functioning markets".[493]

GDFSAE’s views on the current state of information and why further information is required were echoed by:

- the Group of Leading Energy Companies and Major Users (GLECMU), who claimed that there is inadequate information in the market at present for participants to respond to and manage risk and that improvements in the availability and transparency of information are required to facilitate trade, liquidity and to provide clear price signals;[494]

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492 ibid.

493 GDFSAE, Discussion Paper submission, p. 4.

494 GLECMU, Discussion Paper submission, p. 2.

- Stanwell, who claimed the Bulletin Board is difficult to use and has incomplete information;[495]
- QGC, who stated that information is critical to facilitating an effective and liquid market and that capacity trading arrangements and "within-day" pricing cannot be implemented without "meaningful market information to support trade";[496]
- ERM Power, who noted the importance of having an appropriate level of information on the Bulletin Board to help participants make informed trading and investment decisions and manage their commercial gas portfolios.[497]

A number of stakeholders[498] also called for improvements to be made to the Bulletin Board, although some noted that careful consideration would need to be given to the cost of imposing new obligations on parties and confidentiality issues.[499] Some of the more significant improvements that stakeholders suggested could be made to the coverage, timeliness, accuracy and transparency of information in the market are outlined below, while Table 8.2 sets out some of the specific improvements stakeholders suggested should be made to the Bulletin Board:

- *Coverage:* GDFSAE, the GLECMU[500]and Arrow Energy[501] suggested a more centralised and complete reporting framework be developed and encompass both supply and demand. Arrow Energy also suggested a scoping study be carried out to identify what information was required and the most efficient means of meeting those requirements.[502] QGC also suggested a scoping study be carried out and that, going forward, greater emphasis should be placed on information relevant to trading and managing commercial positions than on infrastructure reporting.[503] A number of stakeholders[504] also suggested the coverage of the Bulletin Board be expanded to include information on the LNG producers' activities and noted that without this information other participants in the market could be exposed to more risk and be placed at competitive disadvantage in other markets (eg the NEM).[505]

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495 Stanwell, Discussion Paper submission, p. 7.

496 QGC, Discussion Paper submission, p. 6.

497 ERM Power, Discussion Paper submission, p. 11.

498 APLNG, Discussion Paper submission, p. 1, Arrow Energy, Discussion Paper submission, p. 5, EnergyAustralia, Discussion Paper submission, p. 4 and ESAA, Discussion Paper submission, p. 10.

499 See, for example: ESAA, Discussion Paper submission, p. 10 and GLECMU, Discussion Paper submission, p. 2.

500 GLECMU, Discussion Paper submission, p. 2.

501 Arrow Energy, Discussion Paper submission, p. 5.

502 ibid.

503 QGC, Discussion Paper submission, p. 7.

504 ERM Power, Discussion Paper submission, p. 11, Alinta, Discussion Paper submission, p. 3 and AER, Discussion Paper submission, p. 3

505 In its submission, Alinta stated that there is a "compelling argument" for LNG proponents to be subject to a similar compulsory reporting obligation to that applied to generators in the NEM,

Table 8.2 Suggested improvements to the Bulletin Board

Suggestion		Proponent
Pipeline Information and Information to Support Capacity Trading		
Real time or on the day information on gas flows		APLNG, QGC, GDFSAE, AEMO
Information on linepack and injections and withdrawals		GDFSAE
Capacity availability	Contracted capacity	GDFSAE
	Uncontracted capacity or availability of firm primary capacity for the month ahead and 12 month forecast	APA and APGA
Pipeline utilisation information	Utilisation rates	APLNG and Lumo
	Analysis of historical flows to provide users with a reasonable basis to assess anticipated utilisation	APGA
Information on pipeline constraints		APLNG
Graphical representation of historic daily flows against capacity		APGA
Forecast and current amount of pipeline capacity available for storage		Stanwell
Contact details of each shipper on the pipeline to reduce search costs		APGA and APA
Storage		
Amount of gas available in storage facilities		Stanwell, AEMO
Demand		
New LNG/Gladstone demand zone to capture pipeline flows, capacity outlook and outage information related to these facilities		ERM, AER and Alinta
Comprehensive gas demand data		GDFSAE, Arrow, GLECMU
Listing service		
Listing service for gas		Qenos
Listing service for storage		APLNG
All facilities		
Improve the information that Bulletin Board facilities have to provide on the medium-term capacity outlook		Stanwell and Alinta
Other		
A net system load profile for each hub or network area		Stanwell
Publication of STTM, DWGM and Wallumbilla Gas Supply Hub data on the Bulletin Board		Qenos
Information on transportation costs		Scoping Study and Eastern Australian Gas Market Study

given information on the timing and volume of ramp gas can affect gas and electricity prices. Alinta, Discussion Paper submission, p. 3

- *Timeliness:* Stanwell[506] raised some concerns about the timeliness with which information is published on the Bulletin Board, while QGC[507] and APLNG[508] suggested that some information start to be published on a real-time basis (eg pipeline flows).

- *Accuracy:* Stanwell also raised concerns about the accuracy of the information published on the Bulletin Board and the fact that there is "no penalty or incentive for participants to meet deadlines and for the relevant bodies to enforce the rules".[509]

- *Transparency:* Both GDFSAE and Alinta are of the view that the level of transparency in the gas market should be at least equivalent to the National Electricity Market (NEM) and "in the spirit of disclosure obligations for the Australian Stock Exchange".[510] Stanwell also suggested that consideration be given to whether greater consistency with the NEM information processes could be achieved.[511]

AEMO agreed with the sentiments expressed by most stakeholders, but noted that its ability to amend the Bulletin Board was constrained somewhat by the provisions in the NGR:[512]

> "The Bulletin Board's current regulatory framework is rigid and has not evolved alongside an increasingly complex gas network. Without sufficient information about storage or any large user information, the current information is incomplete. The Bulletin Board has the potential to further complement gas markets by providing more relevant and dynamic information (such as real-time data) and information about storage to better inform trading positions."

Emergency arrangements

In its submission to the Discussion Paper, Alinta noted that gas emergency management and shortage issues are currently managed in a "disparate fashion and at a jurisdictional level". Alinta therefore suggested that further consideration be given to whether a coordinated approach can be adopted that allows jurisdictions to retain control but allows AEMO to act as the agent in charge of managing technical issues.[513]

This issue was also touched on during the Scoping Study, with a number of stakeholders noting the need for greater transparency around the curtailment

506 Stanwell, Discussion Paper submission, p. 7.

507 QGC, Discussion Paper submission, p. 6.

508 APLNG, Discussion Paper submission, p. 1,

509 Stanwell, Discussion Paper submission, p. 7.

510 GDFSAE, Discussion Paper submission, p.4 and Alinta, Discussion Paper submission, p. 3

511 Stanwell, Discussion Paper submission, p. 7.

512 AEMO, Discussion Paper submission, p. 2.

principles to be employed in an emergency and a more comprehensive set of information to be made available during emergencies.[514]

8.3 AEMC's Stage 1 findings and recommendations

In our Stage 1 Draft Report, we sought stakeholder feedback on the following measures that could improve the availability and reliability of market making information on the east coast gas market:[515]

- *Improving price transparency: introducing a gas market price survey or aggregating existing information:* to improve the degree of transparency around wholesale gas prices (or price expectations), transportation costs and the price of other risk management services; and

- *Developing the Bulletin Board and addressing information gaps:* to establish the Bulletin Board as a "one-stop shop," address some of the more obvious information gaps in the Bulletin Board through the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and set a strategic direction for the Bulletin Board.

Stakeholder feedback and our final Stage 1 recommendations on these measures are discussed below. The Commission is aware that information provision is not costless and that there might be genuine reasons for some information to remain confidential. We are also aware that any additional reporting obligations should be targeted, fit for purpose and proportionate to the issue they are intended to address.

8.3.1 Submissions to the Stage 1 Draft Report

The Stage 1 Draft Report sought feedback from stakeholders on options to increase wholesale gas price transparency as a transitional measure until there is an efficient reference price. Two potential options were suggested to achieve transparency in the short-term:[516]

- developing a survey-based gas price index for short, medium and longer-term contracts (e, six months, three years and five years) with basic terms and conditions and supply from the major delivery points (ie Wallumbilla, Moomba, Longford, Port Campbell and Yolla); and

- aggregating existing publicly available information and anecdotal reports on gas prices into a monthly, quarterly or bi-annual report and publishing this on the Bulletin Board.

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513 Alinta Energy, Discussion Paper submission, pp. 8-9.

514 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 101.

515 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Draft Report, 7 May 2015, pp. 32-37.

516 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Draft Report, 7 May 2015, p. 35.

The draft report also sought feedback on establishing the Bulletin Board as a "one-stop shop" for market participants, further improving its usability and functionality, and providing participants with greater confidence in the Bulletin Board data. Opportunities for aggregation of publicly available market data were also suggested, along with other Bulletin Board and informational improvements.

Finally, the draft report put forward that some of the informational matters raised by stakeholders in response to the Discussion Paper could potentially fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change.

Stakeholder views on these issues are discussed below.

Stakeholder views on introducing a gas market price survey and/or aggregating existing information

There was some support from stakeholders for the introduction of a gas market price survey. Jemena and EUAA indicated support for a price index, however both raised concerns associated with the collection and use of confidential information for the index.[517] APA suggested that there is merit in developing trusted price indices to support the development of "more liquid secondary trade of gas, as well as financial hedging produces, which will improve the overall competitiveness of the gas sector".[518]

However, a number of stakeholders did not support the introduction of a price index and generally considered that such an index would be of little value, either due to the difficulty in developing a meaningful index, or the little gain that would be achieved by creating an index, given the presence of existing prices indexes.[519] There were also concerns about the veracity and reliability of information, and the vulnerability of a price index to manipulation. AGL, for example, considered that a price index could "set unrealistic expectations, would be challenging to interpret and have, in the past, brought a number of markets into disrepute due to manipulation (Libor scandal)".[520]

GDFSAE, while not opposed to the development of a survey-based price index, noted that such an index would be of less value than accurate prices that reflect present supply and demand conditions.[521] Further, GDFSAE noted that a price index must aid decision-making, and a liquid market and forward curve provide a better input to decision-making than a historical price index.[522] Despite these concerns (and noting the existence of price indexes in the market), GDFSAE suggested that the development of a price index should be carried out through industry agreement and provided by a

517 Jemena, Stage 1 Draft Report submission, p. 2, EUAA, Stage 1 Draft Report submission, p. 2.

518 APA, Stage 1 Draft Report, p. 22.

519 For example, AEMO, AGL, Santos, GDFSAE and QGC did not support the introduction of a price survey.

520 AGL, Stage 1 Draft Report submission, p. 2.

521 GDFSAE, Stage 1 Draft Report submission, p. 2.

522 ibid.

private entity that already provides such an index, and continue for three years until the index's usefulness is assessed by market participants.[523]

Santos does not support the development of a survey-based price index, noting that a "vanilla index would be meaningless as customers look for a price that has individual contract and load characteristics".[524]

Stanwell echoed the observations by other stakeholders about the difficulty in creating a meaningful price index: "in the absence of an active liquid market in gas derivatives, it would be very difficult for the survey-based gas index to achieve the International Organization of Securities Commissions (IOSCO) principles of financial market data." Stanwell noted that the Australian Financial Markets Association attempted to construct a benchmark but did not proceed with it due to the difficulty in achieving compliance with IOSCO standards.[525]

In relation to the Stage 1 Draft Report request for feedback on aggregating publicly available information, Santos considered the measure may assist those market participants who do not have the time or expertise to collect the information into one place.[526] AGL also considered that, "while major gas suppliers and buyers already undertake this analysis to inform their commercial decisions, this information would be useful to participants who are less well resourced".[527]

In contrast, QGC suggested that information aggregation would "only have a minor effect on overall market efficiency and trading", noting that most market participants have records of public information, or can access it if needed. Instead, QGC (and GDFSAE) recommended that a scoping study be initiated to identify relevant market data to assist in the short-term trade of gas and pipeline capacity.[528]

Stakeholder views on addressing additional information gaps

Generally, stakeholders were supportive of the AEMC considering whether the inclusion of these, and other matters would fall within the scope of the rule change proposal, where costs, relevancy of the information and confidentiality concerns will be taken into account.[529] In particular, Origin suggested:[530]

> "It is appropriate that the AEMC review information gaps that fall within the scope of this rule change as part of its rule change assessment process to ascertain whether there is additional information that delivers the intended purpose of the rule change and contributes to the National Gas Objective."

523 GDFSAE, Stage 1 Draft Report submission, p. 3.

524 Santos, Stage 1 Draft Report submission, p. 2.

525 Stanwell, Stage 1 Draft Report submission, p. 3.

526 Santos, Stage 1 Draft Report submission, p. 2.

527 AGL, Stage 1 Draft Report submission, p. 2.

528 QGC, Stage 1 Draft Report submission, p. 3; GDFSAE, Stage 1 Draft Report submission, pp. 3-4.

529 For example, AGL Energy, APGA, ESAA, Energy Australia, EUAA and APLNG.

530 Origin, Stage 1 Draft Report submission, p. 3.

However, APA considered that the potential inclusion of some of the matters listed above[531] in the rule change represent:[532]

> "...an unnecessary repetition of areas of information disclosure that have recently undergone close policy consideration and stakeholder consultation, with resulting conclusions that this information should not be required to be published."

APGA also cautioned against further reviewing changes to medium-term capacity information until the National Gas Bulletin Board Capacity Outlooks rule change, which commenced in January 2015, has been given a chance to operate."[533] Santos expressed concerns about the inclusion of information on storage facilities that are part of the processing facility, where gas from that facility still requires processing and is not necessarily a separate injection point into a pipeline.[534]

QGC and GDF Suez recommended the AEMC initiate a scoping study, supported by a working group with representatives from industry, AEMC, AEMO and government, to "identify relevant and meaningful market data to assist and facilitate short-term trade in gas and pipeline capacity."[535]

Stakeholder views on a strategic review of gas market information and the development of the Bulletin Board

Stakeholders generally acknowledged and supported the need for a comprehensive review of the informational needs of the gas market and the role of the Bulletin Board. In particular, AEMO considered:[536]

> "As part of this review, AEMO would be in favour of the AEMC establishing a vision for the development of the Bulletin Board, consistent with the [Energy] Council's vision. The vision should be focussed on developing the Bulletin Board as a tool with which to support short- and long-term decision-making in gas markets through improved transparency and availability of gas market information. This could...be aimed at improving coverage and information required to support risk management in the wholesale market."

AEMO went on to add that it hopes this review will present an opportunity for a thorough review of the Bulletin Board rules (Part 18 of the NGR), particularly as it provides a chance to clarify the application of the rules to some facilities, definitions

531 In particular, linepack data and improvements to the medium term capacity outlook.

532 APA, Stage 1 Draft Report submission, p. 23.

533 APGA, Stage 1 Draft Report submission, pp. 4-5.

534 Santos, Stage 1 Draft Report submission, p. 4.

535 GDFSAE, Stage 1 Draft Report submission, p. 3. See also: QGC, Stage 1 Draft Report submission, p. 3.

536 AEMO, Stage 1 Draft Report submission, p. 2.

and rules around registration and exemption requirements.[537] Other stakeholders noted the need to direct efforts to improving the accuracy and timeliness (through improved enforcement and compliance) of the existing information and data provision.[538]

However, some stakeholders expressed concerns about the costs associated with additional information provision and with Bulletin Board enhancements.[539] There are also questions about the value of providing extra information and establishing the Bulletin Board as a "one-stop shop." AGL noted that it "supported initiatives to develop the Bulletin Board as a "one-stop shop", where benefits outweigh the costs."[540] Jemena suggested principles by which any new information requirements should be assessed:[541]

> “For each proposed new type of information, the following should be clearly articulated:
>
> - the market participants that require the information;
> - the purposes for which they require it (and whether those purposes will further the achievement of the market's objectives);
> - the benefits likely to be gained by publishing the information and the parties to which they accrue; and
> - the costs likely to be incurred in publishing the information and the parties to which they accrue.”

APA suggested that care should be taken not to "socialise" the costs of participants procuring information for their commercial needs.[542]

8.3.2 Final Stage 1 findings

In light of submissions, we have given further consideration to the potential actions to improve transparency on a more immediate basis that were discussed in the Stage 1 Draft Report.

As noted by stakeholders, a certain amount of price information is available in the market, some of which is publicly available and some reported by private providers. There would therefore appear to be some value in one body aggregating this information and publishing this is in a single report.

537 ibid.

538 For example, Origin and Stanwell.

539 Including APA, EUAA, Santos, Origin, Alinta, AGL, CQ Partners and ESAA.

540 AGL, Stage 1 Draft Report submission, p. 2.

541 Jemena, Stage 1 Draft Report submission, p.3.

542 APA, Stage 1 Draft Report submission, p. 26.

However, analysis that we have undertaken suggests that much of the information supplied by private providers and the media is likely to be based on anecdotal reports, in that we have been unable to substantiate them from publicly available primary informational sources (eg ASX statements by the buyers or sellers). Excluding such anecdotal reports would therefore substantially restrict the amount of information that could be aggregated. However, there would be likely to be commercial restrictions that would complicate any attempts to include this information.

More generally, it is also not clear that it would be appropriate for a body such as AEMO or the AER to publish information that it was unable to substantiate. For these reasons, we do not consider that there would be value in committing resources to further pursuing this option at this time.

We have considered stakeholder feedback in relation to the scope of the Energy Council's Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change proposal (see Table 8.1), and the Commission will consider whether there are any other informational gaps that fall within the scope of the proposed rule change that could also be dealt with at this time.[543] This could provide an efficient and timely way of addressing information gaps that require changes to made to the rules.

The Commission intends to release a consultation paper on the rule change later in July 2015. The paper will raise the possibility of including suggestions made by stakeholders for additional information, such as data on storage facilities and volumes, data on linepack, as well as potential improvements to the medium-term capacity outlook information that Bulletin Board facilities are required to provide to AEMO.

As discussed below, the Commission will also shortly establish a working group to undertake a strategic review of gas market information needs, particularly the development of the Bulletin Board. This will allow for the consideration of the other suggestions made by stakeholders, and by the Commission in the Stage 1 Draft Report, for potential improvements to the Bulletin Board that could be implemented without a rule change.

The Stage 1 Draft Report also tested the idea of developing an index based on participants' price expectations in order to resolve the lack of market-based 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 who may be better placed to produce this service (ie Argus and Platts).

543 The scope of the rule change has been described by the Energy Council as rules "relating to the provision of gas pipeline flow and facility data that will: improve the operational management of facilitated wholesale gas markets; better inform the development of the GSOO; and enable a more accurate understanding of gas flows in Australia's east coast gas market and in turn allow a better representation of gas flows to be published on the Bulletin Board". COAG Energy Council, National Gas Rule Change Request and Proposal – Gas Transmission Pipeline Capacity Trading: Enhanced Information, 30 March 2015, p. 3.

While the Commission agrees with these views, the lack of price transparency is a significant issue for large gas users, policy makers and other stakeholders as there is no authoritative source of information on the movements and drivers of gas prices payable under confidential bilateral contracts.

The Commission therefore considers there is value in pursuing the development of an indicator to measure average price movements in gas supply agreements. This could be done by an authoritative organisation, such as the Australian Bureau of Statistics (ABS), which would undertake a survey of the prices paid under bilateral gas contracts. The index would increase transparency around how bilateral gas contract prices are changing over time, without compromising the confidentiality of those contracts.

8.3.3 Final Stage 1 recommendation

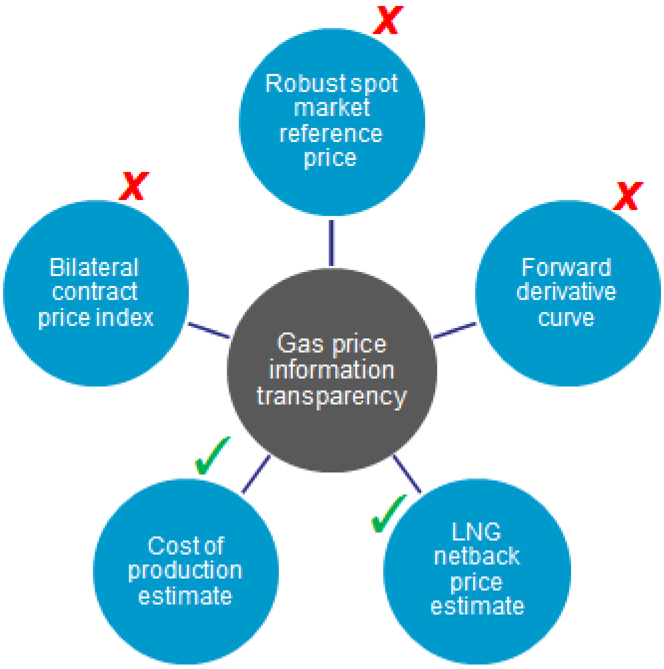
From initial discussions held with the ABS, we understand that a price index could be compiled as an extension of the existing Producer Price Index by surveying large gas users who purchase gas directly from producers, including industrial users, gas-fired generators, retailers and LNG producers. The prices payable by survey participants would be weighted according to a methodology to be developed by the ABS. Data would be collected and the index published quarterly (lagged by approximately one month) in line with the Producer Price Index.

Due to the different supply and demand fundamentals of each market, the AEMC sees value in the ABS establishing both an Australian (including WA/NT) and eastern Australian (excluding WA/NT) index; however, the eventual level of aggregation will depend on whether sufficient data can be collected by the ABS to ensure its strict confidentiality criteria are met. If the establishment of the index is pursued, the AEMC would facilitate a workshop between industry and the ABS to discuss the methodology, data collection process, confidentiality arrangements and any other issues.

In working to progress this initiative, the Commission considers it important to be clear on the strengths and weaknesses of a bilateral gas contract price index, including how it fits into the broader information transparency context.

As can be seen in Figure 8.2, gas price transparency comprises a number of factors, including a robust spot market reference price that can underpin forward prices, and cost of production and LNG netback estimates, which provide an indication of price floors and ceilings, respectively. While LNG netback and cost of production estimates are available to market participants and policy makers, a robust spot market reference price and forward price, as well as information on prices payable under bilateral contracts, do not yet exist (as Figure 8.2 illustrates).

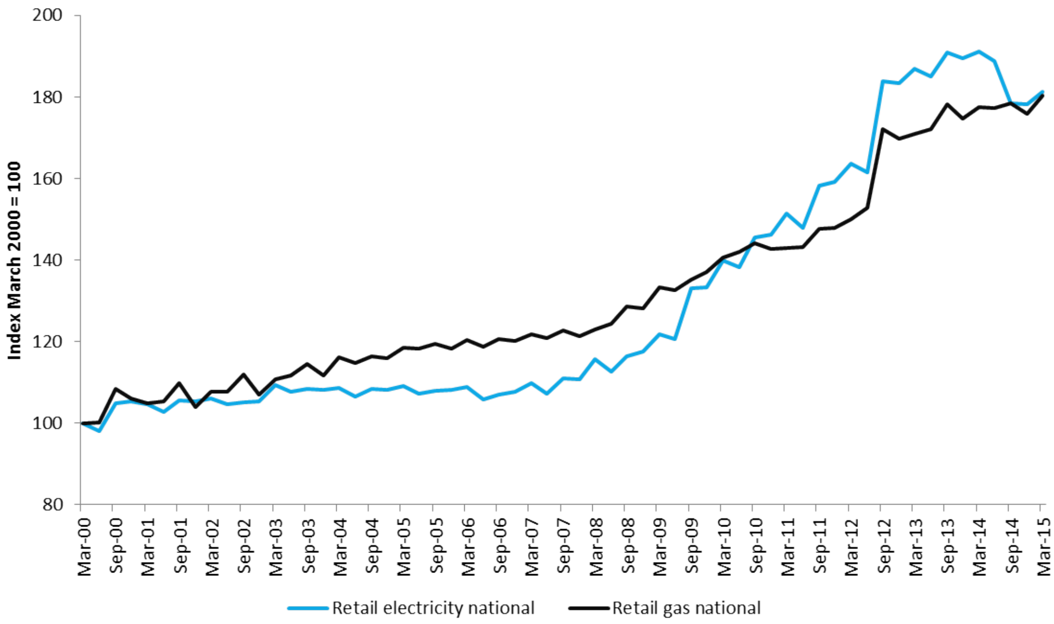
Figure 8.2 Assessment of price transparency in the east coast market



A bilateral gas contract price index is one piece of information that could assist participants and other stakeholders to establish a comprehensive picture around wholesale gas prices. Unlike the initiative put forward in the Stage 1 Draft Report, the ABS index would not be based on a survey of price level expectations, which submissions have argued is open to manipulation. It would instead be based on the prices paid under existing contracts using well-established data collection processes and index calculation methodologies used by the ABS. Index numbers and not price levels would be reported in a similar manner to the ABS electricity and gas retail price indexes in Figure 8.3 below.

In this respect, the ABS index would not be a substitute for a deep and liquid trading market that facilitates the development of a robust reference price, or a credible forward curve that assists participants to form price expectations. It is also unlikely to contribute greatly to the price discovery process by itself or be an accurate indicator of future gas prices. However, the index would provide an additional source of information that is currently unavailable on how the prices payable under confidential bilateral contracts are changing over time – the percentage change in index numbers between two periods representing the percentage change in average gas prices.

Figure 8.3 ABS retail price index (inflation adjusted) - electricity and gas



ABS, Consumer price index, cat. no. 6401.0, various years; Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

At any one time the index will be made up of a basket of gas contracts with different pricing structures that result in different individual price movements. Therefore movements in the index are unlikely to directly correspond to price changes in any single gas contract, just as movements in the Consumer Price Index (CPI) are unlikely to correspond to changes in any single good or service that make up that index. However, the trend established by the index would provide transparency around the direction and magnitude of movements in average prices in bilateral gas contracts.

Given that prices payable under gas contracts have (we understand) been historically linked to CPI, we would expect movements in the index to closely match movements in the CPI in the early stages. However, as existing gas contracts roll off in the next one to two years and new contracts are negotiated and captured by the index, we would expect movements in the index to reflect the pricing structures adopted in these new contracts, which may be linked to a benchmark oil price, a combination of CPI and oil prices, or potentially the Wallumbilla GSH price in the future.

As well as being a measure of price inflation and providing an indicator of pricing structures in bilateral gas contracts, the index itself could also be used for indexation of gas contracts or other industry costs, although this would be a commercial decision and is not the primary purpose of the index.

8.4 Stage 2 directions

This section sets out the direction for the information workstream that will be progressed in the context of Stage 2 of the review. The Stage 1 recommendation set out above can be implemented more immediately, whereas the measures outlined in this section require further consideration.

8.4.1 Strategic review of gas market information needs and development of the Bulletin Board

During Stage 2, the AEMC will undertake a broad review of the adequacy of gas market information available to market participants, including the future role of the Bulletin Board. This work will consider the role of information in the development of a more liquid wholesale gas market and will be supported by a technical working group comprised of representatives from industry, governments and market bodies.

In particular, we will examine more closely the key questions relating to information provision, such as who should be responsible for providing it, how it should be provided and to whom, to what extent does information provision need to be mandated and what role can the market and private providers play.

The Bulletin Board is the main mechanism through which information is disseminated, and the focus of the working group will therefore be its potential further development. This will include the merit of establishing it as a "one-stop shop" to meet gas market informational needs, and our preliminary thoughts on the changes that could be made to the Bulletin Board to increase its scope and improve its usability and functionality are outlined in Table 8.3, below. However, the group will also need to re-examine the structure underpinning the Bulletin Board, for instance which pipelines are included and its ability to accommodate bidirectional pipelines.

Having regard to the progression of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change request and the other Stage 2 work on market design (which may alter the role and nature of information required by the market), the information workstream will need to consider the following detailed questions:

- Governance: What should the Bulletin Board governance framework look like? Is it appropriate that some Bulletin Board information provision definitions and requirements are embedded within the NGR (such as Bulletin Board pipeline definitions and the requirements listed in Figure 8.3), whereas others are embedded in AEMO operating procedures (such as zone definitions)? Who should be responsible for strategic oversight of the Bulletin Board? What is the best way of collecting, organising and disseminating information at least cost? How should costs be allocated among market participants?
- Content and coverage: What specific information across the supply chain is required to facilitate the development of a more informed market? Should the coverage of the Bulletin Board extend to large users as it does in Western Australia? Is information on exploration and reserves required on the Bulletin Board? Given the dynamism and information-intensity of the market, is more timely information now required? In what areas is more timely information required? How important is real-time information as opposed to ex post information? Is something approaching the continuous disclosure requirement in the ASX required?

Table 8.3 Possible improvements to the Bulletin Board

Improvement	Detail
Include information on prices from the facilitated markets	Develop a new facilitated markets pricing page that includes: • current and historic information on prices and other relevant information from the Gas Supply Hub, STTM and DWGM • the AER's Weekly Gas Market Report.
Include planning and longer term forecasts information	Develop a new long-term forecast and planning page that includes the GSOO, the National Gas Forecasting Report and associated material.
Expand the scope of capacity listing	Expand the scope of the capacity listing page to include a separate listing service for gas, transportation and storage capacity.[544]
	Consider, in consultation with APA and JGN, the extent to which bids and offers on their respective capacity trading sites could also be published on the Bulletin Board so that prospective shippers can find this information on a single website.
	Reconsider whether market participants should be required by the Bulletin Board procedures to list available gas or spare capacity through the GSH, given the financial and logistical hurdles this may present.
Allow transportation and storage charges to be published	Consider developing a section on the Bulletin Board that can be used by pipeline operators and storage operators to post their transportation and storage charges.
Further improvements to the Bulletin Board's layout and functionality	Continue to improve the usability and functionality of the Bulletin Board by, for example: • making key information easier to find on the home page;[545] • developing separate pages for production, transmission and storage, which would include the information Bulletin Board facilities are required to provide AEMO; • providing greater clarity about what some of the data represents;[546] • making greater use of some of the information provided by Bulletin Board facilities[547] and improving the website's charting capability;[548] and • establishing a new section for the Bulletin Board procedures and the AER's compliance reports.

544 Rule 176 currently allows Bulletin Board participants to notify other Bulletin Board users if they have 'spare capacity'. The term 'spare capacity' is not a defined term in the NGR, so it is possible that this term could be interpreted as spare transportation, storage or processing capacity.

545 The Western Australian Gas Bulletin Board and the National Grid's Prevailing View site are useful examples that could be drawn on when considering this issue.

546 For example, it is unclear at present whether daily production data includes or excludes gas that is put into storage.

547 For example, the information on actual flows and standing capacities could be used to calculate an historic utilisation rate to help shippers that are considering access to a pipeline.

548 For example, the actual flow data charting capability could include information on standing capacities as well as actual flows.

- Functionality: How could the functionality, usability and usefulness of the Bulletin Board be improved (eg data management and charting functionality)? Are there opportunities to streamline the provision and display of data? As noted, Table 8.3 sets out our preliminary views on the improvements that could be made to the Bulletin Board in this regard. There may, of course, be other relatively simple improvements that can be made to the Bulletin Board, which will be identified through the working group.

- Compliance and enforcement: How could the accuracy of information provided by Bulletin Board facilities be improved? Are more effective enforcement mechanisms required to encourage Bulletin Board facilities to provide accurate and timely information? Should the information that Bulletin Board facilities provide be subject to a specific standard (eg a "best estimates arrived at on a reasonable basis" test)? Is the presence of civil penalty provisions in the NGL effective in encouraging compliance, and is there a need to expand the coverage of these provisions? Are there opportunities for the AER and AEMO to streamline the process for monitoring and enforcing compliance, to identify and address areas of systemic non-compliance in a timely manner?

8.4.2 Emergency arrangements

The final matter that was raised in Discussion Paper submissions that warrants further consideration are the arrangements that have been put in place to deal with emergencies extending beyond one jurisdiction. These arrangements are currently set out in the National Gas Emergency Response Protocol Memorandum of Understanding (Protocol).[549] In short, the Protocol:

- recognises that commercial arrangements should be allowed to operate, as far as possible, to address any shortfall in supply and maintain system security, and that the exercise of a jurisdiction's emergency powers should only occur as a last resort;

- provides for the establishment of the National Gas Emergency Response Advisory Committee (NGERAC) and sets out the functions and roles it is to play;

- specifies the principles that should guide the Energy Council and jurisdictions when considering the advice of NGERAC and any potential use of jurisdictional emergency powers; and

- sets out the consultation that should occur between affected jurisdictions.

Stakeholders in the Scoping Study also raised some concerns about these arrangements. The study suggested that these comments be passed onto the then Australian Government's Department of Industry along with their high level observations on the need to:

549 This is a non-binding Memorandum of Understanding that was entered into in 2005 by the Australian, State and Territory governments.

- improve the transparency and accessibility of the arrangements and provide greater clarity about the following matters by either updating the Protocol, or moving the emergency arrangements into the NGL and NGR:
  - the role to be played by AEMO during an emergency;
  - the circumstances in which NGERAC will be convened;
  - any immunity NGERAC and AEMO may have from liability; and
  - the principles to underpin curtailment tables and gas sharing arrangements;
- formalise the industry's obligations to provide information in emergencies; and
- review jurisdictional curtailment tables to determine whether they are still appropriate and consider whether such tables should be publicly available.

There was limited response from stakeholders on this issue, however APA indicated it would welcome a more consultative and interactive approach to energy security planning, and developing clearer processes in respect of emergencies.[550]

The AEMC understands from the White Paper that a review of the Protocol is to be carried out and considered by the Energy Council in 2015–16.[551] The AEMC will seek to gain further understanding on emergency arrangements and future work plans throughout Stage 2 of the review to inform consideration of any potential improvements or gaps in this process.

550 APA, Stage 1 Draft Report submission, p.27.

551 Department of Industry and Science, *Energy White Paper 2015*, April 2015, p. 30.

A East Coast Wholesale Gas Market and Pipeline Frameworks Review: 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.

The 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

Milestone	Due Date
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 Terms of Reference – Victorian Declared Wholesale Gas Market Review

Background

The Victorian Government recognises that improvements may be made to the operation and efficiency of the eastern Australian gas market, to better facilitate market transparency and transmission capability, and increasing gas supply to meet rising demand at competitive prices.

The Victorian Declared Wholesale Gas Market (DWGM) is a single integrated market that provides participants with the ability to trade imbalances and purchase wholesale gas. The market was established by the Victorian Government in March 1999 to support full retail contestability and encourage diversity of supply and upstream competition.

The DWGM is operated by the Australian Energy Market Operator (AEMO). Between 1999 and 2007, the gas price was determined on a daily ex-post basis. From 2007, the market moved to ex-ante intra-day trading following a review by VENCorp in 2003-04, which found that the existing design did not provide participants with the ability to respond to changing market conditions throughout the day.

The DWGM facilitates trading and balancing arrangements for gas market participants, including retailers, gas-fired generators, large industrial users and producers. Since the inception of the DWGM, the market design has stimulated a competitive retail gas market and safeguarded the security of gas supply for Victorian customers. Currently, there are eight gas retailers competing in the retail market and six gas-fired generators connected to the Victorian Declared Transmission System (DTS). Notwithstanding this, substantial developments are set to impact the market over the next few years.

In response to the establishment of a liquefied natural gas (LNG) export industry, the east coast gas market will experience a structural change to demand and supply. Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with end users in these states likely to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect Pipeline or Eastern Gas Pipeline. With exports set to begin from late-2014, the domestic market is already feeling the effects of greater competition for gas. These developments are expected to put upward pressure on gas prices and have resulted in a renewed focus on the efficiency of the gas supply chain.

Given the uncertainty around market outcomes for participants, gas market arrangements need to be flexible enough to support a range of potential scenarios out past 2020. It will be important for end users, such as industrial and commercial customers, as well as retailers, to have the ability to effectively manage risk in the DWGM. To minimise inefficient congestion on the DTS, investment to expand the DTS needs to occur in a timely and efficient manner. Interaction between the DWGM and adjacent gas markets should also be as seamless as possible, as this will reduce transaction costs and unnecessary volatility for market participants, minimising costs for end users of natural gas.

It is critical that a review of the Victorian DWGM be undertaken to examine whether the significant structural changes underway in the eastern gas market require reforms to enhance the liquidity, transparency and flexibility of the current arrangements.

In this context, the Victorian Government has requested that the Australian Energy Market Commission undertake, in consultation with AEMO, a thorough review of pipeline capacity, investment, planning and risk management mechanisms in the Victorian DWGM. The objective of this undertaking is to ensure arrangements for access to the pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.

The AEMC will undertake the review in accordance with this Terms of Reference and provide a report with recommendations to the Victorian Government for consideration. The Victorian Government notes that the COAG Energy Council has separately tasked the AEMC with reviewing the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast. The two reviews are related in scope and similar in timing and it is expected that the relevant findings and recommendations to be reflected in both reviews (where appropriate).

Purpose

The review is to consider whether the DWGM provides appropriate signals and incentives for investment in pipeline capacity, allows market participants to effectively manage price and volume risk, and facilitates the efficient trade of gas to and from adjacent markets. More broadly, the review is to consider whether and to what extent the DWGM continues to effectively promote competition in upstream and downstream markets, in the long term interest of consumers.

These Terms of Reference are intended to guide the AEMC's review of the Victorian DWGM.

Scope

The AEMC is required to undertake a review of the Victorian DWGM that considers:

1. Effective risk management in the DWGM: the ability of market participants to manage price and volume risk in the DWGM and options to increase the effectiveness of risk management activities.

The Victorian Government is concerned that an inability for market participants to effectively hedge risk in the DWGM is limiting the potential of the market to achieve greater transparency and efficiency of trade in natural gas.

The ASX Victorian Wholesale Gas Futures Product is available but not widely traded as it can only be used to hedge against the ex-ante market price and not uplift charges. Further, while Authorised Maximum Daily Quantity (AMDQ) and AMDQ credit certificates provide participants with some protection against uplift charges, they cannot be used as a hedge against surprise or common uplift charges.

The AEMC is to investigate the underlying issues that are preventing greater use of derivatives and other risk management tools in the DWGM, outline the features of an efficient financial derivative market for gas and the changes that would need to be made in the DWGM to facilitate this.

2. Signals and incentives for efficient investment in and use of pipeline capacity: whether market signals and incentives are providing for efficient use of, and efficient and timely investment in, pipeline capacity on the DTS.

Investment decisions to augment the DTS are currently largely made in response to a five year regulatory determination process. While the DWGM arrangements provide a form of tradeable pipeline capacity rights, through AMDQ and AMDQ credits, these rights have limitations in terms of providing certainty of access when the pipeline is constrained, and in allowing “free-rider” access when spare capacity is available. Consequently, they have been of limited effect in supporting private pipeline investment in the DTS. Investment guided by regulatory processes may be less efficient and timely than relying on market driven incentives. If firm, tradeable access rights to pipeline capacity were available, in a form that addressed these current limitations, this may enhance private investment, as prices for the access rights would signal the need for future investment.

The AEMC is to investigate whether investment in the DTS is expected to continue to occur in a timely and efficient manner. This investigation should also consider the interaction between regulated and private investment and whether the costs of pipeline investment and usage are allocated to users on an equitable basis. If appropriate, the AEMC is to recommend changes to strengthen the signals and incentives for efficient investment, and enhance access to, and short term trading of, pipeline capacity.

3. Trading between the DWGM and interconnected pipelines: To maximise the efficiency of trade in natural gas and facilitate competition in upstream and downstream markets, producers and shippers should be able to effectively operate across the different gas trading hubs on the east coast without incurring substantial transaction costs.

The AEMC is to examine if, and to what extent, the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines. Elements like transparent, adaptable pricing between the DWGM and interconnected pipelines, combined with ready access to pipeline capacity, may be required to enable shippers to better manage risk and facilitate the efficient trade of gas between interconnected hubs and pipelines.

In considering items 1 and 2 above, the AEMC should examine alternative pricing, risk management and pipeline access mechanisms for the DWGM that would also enhance efficient trading of gas with interconnected pipelines and facilities.

4. Promoting competition in upstream and downstream markets: whether the DWGM arrangements continue to facilitate market entry and promote competition in upstream and downstream markets and how this could be improved.

Taking into account the analysis and any recommendations from the areas of review above, the AEMC should assess whether the DWGM continues to effectively encourage the introduction of new gas supplies to the market and promote competition among retailers in the sale of gas. The AEMC should also comment on the extent to which the design of the DWGM may be a deterrent to large users of gas from participating in the market where it may otherwise be commercially practical for them to do so, and the extent to which this may have an adverse impact on gas usage, trading and market liquidity.

If the AEMC proposes recommendations for market reform, it should clearly demonstrate to the Victorian Government and Council of Australian Government's (COAG) Energy Council how the recommendations address the issues identified, that they continue to safeguard the security of gas supplies to Victorian customers, are proportionate to the problem being addressed and how they promote the national gas objective.

Considerations

In undertaking the review and forming its recommendations, the AEMC is to consider:

- the physical characteristics, size, maturity and interconnectedness of the Victorian gas market;
- the nature of the commercial arrangements underpinning the supply and transportation of gas;
- developments in other eastern Australian gas markets; and
- relevant international experience.

The AEMC is also to consider and incorporate (where appropriate) the findings and recommendations from its concurrent review of Australia's facilitated gas markets.

More broadly, the AEMC is also to consider.

- the National Gas Objective; and
- the COAG Energy Council's Gas Market Development Plan.

Consultation

The Victorian Government requires that the AEMC undertake a formal stakeholder consultation process, including the release of an issues paper, options paper and a draft report for consultation at minimum. If considered appropriate, the AEMC should also hold public forums and/or workshops.

The AEMC is required to establish a stakeholder reference group that will meet periodically throughout the review and prior to the completion of each of the review milestones, and comprise membership of AEMO, representatives of pipelines, consumers, retailers, producers, large users and any other party the AEMC deems appropriate. This stakeholder reference group will also be used for the AEMC's review of facilitated gas markets on the east coast and additional Victorian-specific representatives may be invited.

The AEMC is to utilise the experience of the Australian Energy Regulator as appropriate.

Timeframes and deliverables

The AEMC is to undertake the review over a maximum period of 18 months, taking into consideration the indicative timeframes set out below. This will allow the AEMC to undertake extensive engagement with stakeholders and propose well developed recommendations to the Victorian Government.

The Victorian Government notes that these timeframes represent an upper bound and the AEMC should use its best endeavours to complete each stage of the review promptly and ahead of schedule. Public consultation should be for a minimum of four weeks for each report and a copy of the draft and final reports must be provided to Victorian Government officials and the COAG Energy Council officials one week before publication.

Milestone	Timing
Public forum (in conjunction with the Review of Facilitated Markets)	February 2015
Issues Paper	April 2015
Options Paper	August 2015
Publish Draft Report, including request for Victorian Government response on any significant initiatives identified by the AEMC	December 2015
Final Report	The final report will be published following receipt of the Victorian Government's response to findings and recommendations in the draft report

Before finalising a detailed implementation plan for its proposals in the final report, the AEMC will seek a formal response from the Victorian Government and the COAG Energy Council to some of its recommendations in the draft report.[552]

552 For example, if the AEMC proposes significant changes to the National Gas Rules, the AEMC will seek a response from the COAG Energy Council at the draft report stage before finalising the review.

C Summary of previous reviews of the east coast gas markets

Table C.1 Relevant recommendations from previous east coast gas market reviews and actions

Recommendation	Action
Gas Market Scoping Study[553]	
High Priority Undertake a strategic review that considers both: • the directions that the eastern Australian gas market should take over the next 10-15 years, if it is to make the transition to a more mature, well-functioning market (consisting of commodity, transportation and financial markets) that supports: the efficient allocation of gas in the short, medium and longer-term; the efficient trade and movement of gas between jurisdictions; efficient and timely investments in upstream production and transportation capacity; the efficient allocation of risks; and the development of financial markets that can be used by participants to hedge risks. As part of this assessment, consideration would ideally be given to whether the existing facilitated markets (ie the DWGM and STTM) are meeting their stated objectives in the most efficient manner; and if not, how this could be addressed; and • the principles that should guide the development and design of facilitated markets in the future. SCER (now the COAG Energy Council) to sponsor review; AEMC to carry out review.	At its December 2014 meeting, the COAG Energy Council reaffirmed its commitment to the NGO and outlined its Vision for the east coast gas market. In order to assist the Council realise its Vision, it tasked the AEMC to review the design, function and roles of the facilitated gas markets and gas transportation arrangements. The first stage of this Review will be provided to the Council by mid-2015. The second stage of this review will more fully develop the any necessary medium and long term adjustments required to implement the Energy Council's Vision, including the transition path required.

553 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, pp. iii-iv.

Recommendation	Action
High Priority Undertake a detailed review of the design of the STTM and particular design elements of the DWGM and determine whether improvements can be made to the existing design that would better promote the NGO. AEMC and SCER to jointly draft terms of reference; SCER to determine whether AEMC and/or AEMO should carry out the review once scope of work defined.	
Medium Priority Investigate ways of reducing the time taken to develop and implement STTM and DWGM rule changes and streamline the consultation process (AEMO and AEMC).	The AEMC can expedite non-controversial rule changes under section 304 of the NGL, subject to requests not to do so, and assessed the Removal of the Gas Bulletin Board Emergency Information Page Proposal rule change on an expedited basis. The AEMC is recommending that the Energy Council consider the appropriateness of section 295(3) of the NGL (which restricts parties other than AEMO and Ministers of adoptive jurisdictions from submitting DWGM rule changes). For more information, see Chapter 5.
Medium Priority Two review options that could be taken to promote investment outcomes in the Victorian Declared Transmission System (DTS) are: • Option 1: undertake a holistic review of the regulatory investment process and application of this process in Victoria; and/or • Option 2: undertake a preliminary internal review of the prospects for introducing tradeable transmission rights and proceed to a more detailed public review if tradeable transmission rights are considered likely to provide improved investment signals in the DTS. SCER to sponsor the review; AEMC to carry out the review.	The COAG Energy Council, at the request of the Victorian Government, has tasked the AEMC to undertake a review of pipeline capacity, investment and risk management mechanisms in the Victorian DWGM. This report forms part of Stage 1 of the review.

Recommendation	Action
Medium Priority Consideration to be given to how to reduce search, transaction and co-ordination costs associated with spot or very short term capacity trades (ie capacity trades for periods less than one month) to facilitate the form of capacity trading by shippers (Industry led).	There are now four websites listing capacity trading opportunities: AEMO's Bulletin Board and Gas Supply Hub websites, as well as capacity trading websites managed by APA and Jemena for their respective pipelines.[554] See Chapter 4 for more information on capacity trading. Further opportunities to facilitate short term capacity trades will be considered in the second stage of this review.
Low priority Assessment of whether greater consistency between market parameters in the NEM and imbalance markets to be carried out as part of the STTM and DWGM design review (AEMC and/or AEMO).	Opportunities to improve consistency between market parameters and interactions between the NEM and imbalance markets are discussed in Chapters 5 and 6, and will be considered further in the review.
Low priority If there is a significant change in climate change policies and/or conditions in the NEM that support gas fired generation, then a more detailed review could be undertaken to get a better understanding of the interactions between the two markets and to ensure existing arrangements are fit for purpose. SCER to sponsor review; AEMC to carry out review.	
Low priority Be cognisant of the potential for higher wholesale gas prices to prompt jurisdictions to implement a cap on retail prices that is lower than the efficient cost of supply. If there is any indication this may occur, liaise with SCER and the jurisdictions and inform them of the longer term consequences that such a response may have on retail competition (AEMC).	

554 For more information refer to AEMO's Gas Market Bulletin Board at http://www.gasbb.com.au/Transmission%20Capacity%20Listing.aspx

Recommendation	Action
Low priority Consider whether any additional operators should be designated Bulletin Board facility operators; and consider whether improvements can be made to the quality and accessibility of existing STTM, DWGM and Bulletin Board data (AEMO).	In December 2014, AEMO completed a major upgrade to the Gas Market Bulletin Board. The upgrade was implemented to improve the "useability, availability and reliability of gas data for all participants in the south-east and east coast gas markets".[555] Further opportunities to improve information quality and accessibility are set out in Chapter 8 and will be considered further in the second stage of this Review.
Other Refer stakeholder comments on the effect of the restriction set out in section 295(3) of the NGL on DWGM related rule changes to the Victorian Government and allow it to consider whether there is still a rationale for having this restriction and, if so, whether any improvements could be made to the current process (AEMC to refer to Victorian Government).	The AEMC is recommending that the Energy Council consider the appropriateness of section 295(3) of the NGL. For more information on the DWGM, see Chapter 5.
Other Refer stakeholder comments on emergency arrangements and our high level observations about the need: to improve the transparency and accessibility of these arrangements; formalise the obligations industry have to provide information in emergencies; review jurisdictional curtailment tables; and consider whether such tables should be publicly available (AEMC to refer to SCER).	The Australian Government's Energy White Paper notes the Energy Council will review the National Gas Emergency Response Protocol Memorandum of Understanding to ensure that natural gas supply interruptions are managed in a nationally consistent manner in 2015-16.[556] The AEMC will seek to gain further understanding on emergency arrangements and future work plans throughout the review to inform consideration of any potential improvements or gaps.

555 http://www.aemo.com.au/News-and-Events/News/2014-Media-Releases/AEMO-Launches-New-National-Gas-Market-Bulletin-Board

556 Australian Government, Energy White Paper, 2015, p. 30.

Recommendation	Action
Gas Market Taskforce[557]	
Recommendation 13 Eastern market governments, through SCER [now the COAG Energy Council], accelerate and enhance the implementation of existing reforms under the National Gas Market Development Plan: • pursuing ways of making the voluntary markets for transmission capacity more transparent, flexible, efficient and liquid; • investigating options for developing uniform transmission capacity rights and pursue ways of facilitating more transparent and liquid trade in transmission capacity; • identifying and removing barriers to trading in gas across different downstream markets in order to move towards more consistency and, as far as practicable, a single market design; • drawing on relevant experience from gas markets in other countries, such as the United States, the United Kingdom and continental Europe; and • establishing key performance measures in gas market reform, assessing responsibility for delivering them, and annually commission a review of success and consider further facilitation of market development.	At its December 2014 meeting, the COAG Energy Council updated the National Gas Market Development Plan.[558] Progress toward existing reforms is summarised below: • the Wallumbilla Gas Supply Hub commenced in March 2014 and; • on 30 March 2015, the Energy Council submitted a rule change request to the AEMC to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board. Opportunities to further facilitate trade in transmission capacity and to improve market design, information quality and accessibility are discussed in this report and will be considered further in Stage 2 of this Review. Further, in order to inform this Review, the AEMC has commissioned a study on international gas markets and transmission pipeline frameworks, including in the United States, United Kingdom and some European markets. The study is expected to be published with the AEMC's final Stage 1 report in June 2015.

557 Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, pp. 7-8.

558 http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/

Recommendation	Action
Recommendation 16 The Victorian Government immediately request the AEMC undertakes, in consultation with AEMO, a thorough review of pipeline capacity, investment, planning and risk management mechanisms in the DWGM with the objective of ensuring arrangements for access to pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.	The COAG Energy Council, at the request of the Victorian Government, has separately tasked the AEMC to undertake a review of pipeline capacity, investment, planning and risk management mechanisms in the DWGM. This report forms part of Stage 1 of the review.
Recommendation 17 The Victorian Government to consider whether arrangements for rule-making in the DWGM are adequately responsive to the gas industry given the challenges it is facing.	The AEMC is recommending that the Energy Council consider the appropriateness of section 295(3) of the NGL. For more information on the DWGM, see Chapter 5
Eastern Australian Domestic Gas Market Study[559]	
Gas Market Reform Agenda 1. Consider commissioning a review of gas market competition to focus on matters driving wholesale market outcomes; 2. Complete current SCER [COAG Energy Council] reforms (especially commence Wallumbilla hub and support pipeline capacity trading); and 3. Agree a forward gas market reform agenda in consultation with stakeholders: (a) develop principles to guide policy on commodity, transportation and	At its December 2014 meeting, the Council reaffirmed its commitment to the NGO, updated the National Gas Market Development Plan and set out its vision for Australia's Future Gas Market.[560] In order to assist the Council achieve the vision, it requested that the AEMC review the design, function and roles of the facilitated gas markets and gas transportation arrangements. The Wallumbilla Gas Supply Hub commenced in March 2014. On 30 March 2015, the Energy Council submitted a rule change request to the AEMC to provide enhanced gas transmission pipeline capacity trading

559 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 90.

560 COAG Energy Council, Communique, December 2014 https://scer.govspace.gov.au/files/2014/05/COAG-Energy-Council-Communique-11-Dec-2014-FINAL2.pdf

Recommendation	Action
financial markets; and (b) conduct specific reviews on the direction and structure of the existing trading and related financial markets.	information on the Bulletin Board
Improve the commercial and regulatory environment for infrastructure 1. Improve information to markets and regulators on pricing and utilisation of infrastructure; 2. Review suitability of carriage models for pipeline regulation; 3. Consider support for infrastructure feasibility studies; and 4. Enhanced pipeline capacity trading and develop a roadmap and evaluation process around future development of pipeline capacity trading.	The suitability of pipeline carriage models and options to enhance pipeline information and capacity trading are discussed in Chapters 4 and 8 of this report. and will be considered further in the second stage of this Review.
Market data and transparency 1. Improve planning on transparency mechanisms such as the Gas Statement of Opportunities and Bulletin Board and industry initiatives (eg price indices, pipeline information).	Options to improve gas market information are discussed in Chapter 8 and will be considered further in the second stage of this Review.

D Third party access regime applying to transmission pipelines

D.1 Introduction

The third party access regime applying to pipelines is set out in the National Gas Law (NGL) and the National Gas Rules (NGR), both of which came into effect on 1 July 2008. Prior to 1 July 2008, covered pipelines were subject to the access regime and regulatory framework set out in the *Gas Pipeline Access (South Australia) Act 1997* (GPAL) and the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), which were enacted in late 1997.

While there are some parallels between the access regime applying to gas pipelines and electricity networks, there are also some important points of distinction. For example:

- the gas access regime is more akin to the negotiate-arbitrate model in Part IIIA of the *Competition and Consumer Act 2010* (CCA) than the model used in electricity;[561]
- the economic regulatory provisions in the NGR only apply to covered pipelines;
- a covered pipeline may be subject to either full or light regulation;[562]
- provision has been made in the NGL for a pipeline's coverage status and/or the form of regulation to be altered over time if conditions change and certain criteria are met;
- provision has also been made in the NGL for:
  - a greenfields pipeline to be exempt from coverage for 15 years; and
  - a new international pipeline to be exempt from price regulation, or coverage, for 15 years.[563]

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561 This point can be seen in section 322 of the NGL, which states that subject to section 135, nothing in the NGL is to be taken as preventing a service provider from entering into an agreement with a user or a prospective user about access to a scheme pipeline that is different from an applicable access arrangement.

562 The only exception to this is if the scheme pipeline has been deemed a 'designated pipeline'. A designated pipeline is a pipeline classified by the Regulations, or designated in the application Act of a participating jurisdiction, that cannot be subject to light regulation. The pipelines that are currently designated include AGNL's SA Distribution Network, ATCO's Western Australian gas distribution system, the three Victorian gas distribution systems and the DTS. See National Gas (South Australia) Regulations 2009, National Gas Access (WA) (Part 3) Regulations 2009, Schedule 1 and Victorian Government Gazette No. S222m, 30 June 2009.

563 An international pipeline is defined as a pipeline for the haulage of gas from a foreign source.

The remainder of this appendix provides further detail on the third party access regime and form of regulation provisions in the NGL and NGR, with particular emphasis placed on:

- the background to the development of the these aspects of the regulatory framework;
- how coverage, revocation of coverage and 15 year no-coverage decisions are made; and
- the alternative forms of regulation provided for under the NGL and NGR.

D.2 Background to the development of the current regulatory framework

The third party access regime and regulatory framework currently applying to gas pipelines was developed through two distinct phases of reform. The first phase, which extended from 1991 to 2002, focused on:

- the removal of government imposed constraints on the free and fair trade of gas;
- the development of a framework for third party access to transmission and distribution pipelines on non-discriminatory terms and conditions; and
- the structural reform of the vertically integrated government owned transmission and distribution assets and the privatisation of government owned pipelines and retailing.

In the second phase of reforms, which commenced in 2002 and culminated in the enactment of the NGR and NGL in 2008, the reform agenda shifted focus from structural reforms and access provision, to addressing some of the perceived deficiencies in the regulatory and governance frameworks.

D.2.1 First phase of reforms (1991–2002)

The pre-cursor for the first phase of reforms was a report prepared by the Industry Commission in 1991 entitled, "Energy Generation and Distribution," which contained a number of recommendations on how to remove impediments to the efficient allocation of gas.[564] Between 1992 and 1994, COAG agreed to implement many of the Industry Commission's recommendations including:[565]

- the removal of legislative and regulatory barriers to inter and intra-jurisdictional trade and the use of gas for certain activities to facilitate the free and fair trade of gas;
- the introduction of complementary legislation to enable a national framework for third party access to gas transmission pipelines to be introduced;
- increased commercialisation of the operation of public owned gas pipeline assets; and

564 Industry Commission, *Energy Generation and Distribution*, 17 May 1991.

- the vertical separation of publicly owned transmission and distribution assets.

At the same time that these reforms were being progressed by COAG, the Independent Committee of Inquiry (Hilmer Review) was considering the reforms that would be required to develop a national competition policy.[566] In April 1995, the recommendations flowing from the Hilmer Review were adopted by COAG and implemented through the Competition Principles Agreement (CPA). A key element of the CPA was the decision to allow third party access to services provided by significant infrastructure facilities, through the development of a national access regime that was introduced into Part IIIA of the *Trade Practices Act 1974* (now the *Competition and Consumer Act 2010* (CCA)) (see Box D.1).

Box D.1 Part IIIA of the CCA

Under Part IIIA there are three avenues through which access to an infrastructure service can occur:

1. Through a declaration by the relevant Minister that the services satisfy all of the following criteria.
   - (a) access (or increased access) to the service would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the service;
   - (b) it would be uneconomical for anyone to develop another facility to provide the service;
   - (c) the facility is of national significance, having regard to:
     - (i) the size of the facility; or
     - (ii) the importance of the facility to constitutional trade or commerce; or
     - (iii) the importance of the facility to the national economy.
   - (d) [repealed]
   - (e) access to the service is not already the subject to an effective access regime; and
   - (f) access (or increased access) to the service would not be contrary to the public interest.

If a service is declared then the parties must negotiate the terms and conditions of access to the service. If an agreement can't be reached then the access dispute provisions can be triggered.

2. Through a legally enforceable access undertaking (a document setting out the terms and conditions on which access will be provided, including the price of access), which is voluntarily submitted by the asset owner to the Australian Competition and Consumer Commission (ACCC) for its approval;
3. Through a state or territory access regime that has been certified as an effective regime by the Commonwealth Minister because it complies with the Competition Principles Agreement.

565 National Competition Council, *Compendium of National Competition Policy Agreements*, 2nd ed., 1998, pp. 70-71.

566 Independent Committee of Inquiry, National Competition Policy, August 1993, pg. xvii.

While access to gas pipelines could have been facilitated by the generic national access regime in Part IIIA, COAG decided that an industry specific access regime should be developed to enhance certainty, uniformity and consistency outcomes that were expected to assist with the expansion of the market for gas and encourage investment in pipelines. Elaborating further on this decision, COAG noted that the access regime "involves a balance between flexibility, required to deal with the individual circumstances of pipelines and customers, and a level of prescription to ensure consistency of treatment." [567]

Some of the principles that COAG agreed should underpin this access regime are reproduced below:[568]

- pipeline owners and/or operators should provide access to spare pipeline capacity for all market participants on individually negotiated non-discriminatory terms and conditions;
- information on haulage charges, and underlying terms and conditions, to be available to all prospective market participants on demand;
- if negotiations for pipeline access fail, provision be made for the owner/operator to participate in compulsory arbitration with the arbitration based upon a clear and agreed set of principles;
- pipeline owners and/or operators maintain separate accounting and management control of transmission of gas;
- provision be made for access by a relevant authority to financial statements and other information necessary to monitor gas haulage charges; and
- contracts, between producers and consumers for the supply of gas, entered into prior to the enactment of gas reform legislation would not be overturned by it.

The industry specific regime was set out in the Gas Code, which was given legislative effect in each jurisdiction through the GPAL. The overarching objective of the Gas Code, as stated in its introduction, was to establish a nationally consistent framework for third party access to 'covered' pipelines that would:

- facilitate the efficient development and operation of a national natural gas market and integrated pipeline network;
- promote a competitive market for gas, in which customers are able to choose the supplier they want to trade with;
- provide rights of access on fair and reasonable terms to users and service providers and prevent the abuse of market power by service providers; and
- provide a mechanism for the resolution of disputes in circumstances where a prospective user and the service provider were unable to reach commercial agreement.

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567 House of Representatives, Australia 1998, Gas Pipelines Access (Commonwealth) Bill 1997, Explanatory Memorandum, paras 32-33.

568 NCC, Compendium of National Competition Policy Agreements, January 1997, p. 67. These principles were agreed to on 25 February 1994.

Box D.2 provides an overview of the key elements of the Gas Code.

Box D.2 Key elements of the Gas Code

The key elements of the Gas Code were:

- Schedule A, which contained a list of transmission and distribution pipelines that would be covered from the commencement of the Gas Code. This list included most of the pipelines that had been built before the Gas Code came into effect.
- The coverage provisions, which largely mirrored the declaration and access undertaking provisions in the Part IIIA of the CCA and allowed:
  - a pipeline to become covered if it satisfied all of the coverage criteria (or for coverage to be revoked if one or more criteria were not satisfied);
  - a service provider to voluntarily become covered by submitting a proposed access arrangement (AA) to the regulator for approval; and
  - a pipeline to become covered if it was developed through a competitive tender process that was approved by the relevant regulator.
- The access regulation provisions, which required service providers of covered pipelines to prepare an AA and have the terms and conditions upon which it would provide reference services to third parties and the reference tariff payable for each reference service approved by the relevant regulator. While reference tariffs had to be approved by the regulator, the Gas Code allowed service providers and access seekers to agree to terms and conditions (including the tariff) that differed from those set out in the AA. The reference tariff was therefore seen as a benchmark for access negotiations on contract carriage pipeline.[569]
- The dispute resolution mechanism, which could be accessed by shippers and the service provider if a dispute about access, or the terms and conditions of access arose. While the Gas Code explicitly recognised that users and service providers could agree to alternative terms and conditions (including tariffs) to those specified in the AA, the dispute resolution provisions required the arbitrator to apply the provisions of the AA in the event of a dispute.
- The information disclosure requirements.
- The ring fencing provisions, which were designed to prevent a service provider from: carrying on a related business (ie production, purchase or sale of natural gas); and conferring an unfair advantage on an associate that takes part in a related business.
- The merits review provisions, which could be triggered for coverage and regulatory decisions.

569 In the DTS it is not possible to negotiate an alternative transportation service because it is operated on a simple injection/withdrawal basis. All users of the DTS therefore pay the reference tariff.

D.2.2 Second phase of regulatory reforms (2002–2008)

Following a series of reviews, including the independent review of the strategic direction for energy market reform that was chaired by Warwick R. Parer,[570] the Productivity Commission's 2003-04 review of the gas access regime, [571]and the 2006 Expert Panel report on energy access pricing, [572]COAG decided to implement a new legal, governance and regulatory framework. This new framework commenced on 1 July 2008 and was given effect through the NGL and NGR.[573]

The NGR and NGL are founded on the same negotiate/arbitrate principles as those underpinning the Gas Code and contain broadly similar provisions on coverage, [574] ring fencing, access arrangements, price and revenue regulation, and dispute resolution as those adopted in the Gas Code and GPAL. There were, however, a number of important refinements made to the regulatory framework, including:

- the implementation of an overarching objects clause, the National Gas Objective, and revenue and pricing principles in the NGL;
- introducing the phrase 'material increase in competition' into criterion (a) of the coverage criteria to bring it into line with amendments to the declaration criteria that had been recommended by the Productivity Commission;
- the establishment of the Bulletin Board, which imposed obligations on both regulated and unregulated market participants to provide information to AEMO;
- the inclusion of a 15 year no-coverage option for greenfields pipelines;[575] and
- the introduction of a lighter handed form of regulation.

The last of these refinements was made in response to recommendations by both the Productivity Commission and the Expert Panel (see Box D.3) that:[576]

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570 Parer, Warwick R, Towards a Truly National and Efficient Energy Market, 20 December 2002.

571 In 2003, the Productivity Commission was asked to conduct a review into the gas access regime. In its final report to the Commonwealth Treasurer in 2004, the Productivity Commission raised a number of concerns about the potential for regulation to lead to inefficient investment because of the potential for regulatory error, regulatory risk and asymmetric truncation. The Productivity Commission also recommended a number of changes to the gas access regime, including, amongst others: • introducing an overarching objects clause and clear pricing principles; • ensuring consistency between the coverage criteria and recent amendments to the declaration criteria in Part IIIA of the CCA; • introducing a light handed regulatory option; and • allowing binding 15 year no-coverage ruling to be sought by greenfield pipelines to "reduce the potential chilling effect of regulation on greenfield investments." Productivity Commission, Review of the Gas Access Regime, 11 June 2004.

572 Expert Panel on Energy Access Pricing, Report to the Ministerial Council on Energy, April 2006.

573 Unlike the GPAL and Gas Code, the NGL/NGR has not been subject to a formal review by the NCC to determine whether it constitutes an effective access regime for the purposes of Part IIIA of the CCA. This issue was recently considered by the Productivity Commission as part of its review into the National Access Regime and it concluded that, on balance, the costs of certifying the gas and electricity regimes may outweigh the benefits. See Productivity Commission, National Access Regime, 25 October 2013, p. 23.

574 In the NGR reference is made to 'Scheme Pipelines' which include covered pipelines

575 This provision was included in the GPAL in 2006.

- the degree of regulatory intervention should be commensurate with the degree of market power possessed by the service provider; and
- a less intrusive form of regulation should be applied when a service provider is unable to exercise a substantial degree of market power, because the gap between the price it charges and the 'efficient price' is likely to be small and, as a consequence, the costs of full regulation are likely to outweigh the benefits.

Box D.3 The rationale for light regulation

The Productivity Commission recommended the inclusion of a lighter-handed form of regulation in the gas access regime as an alternative to full regulation where the costs of full regulation are likely to exceed the benefits. Elaborating further on this recommendation, the Productivity Commission noted:[577]

> "Regulation with access arrangements with reference tariffs should be applied only where the net benefits of access arrangements with reference tariffs are markedly greater than the net benefits of the monitoring option. Where the difference in net benefits are marginal or the net benefits of the monitoring option are greater than the net benefits of access arrangements with reference tariffs, then the monitoring option [light regulation] should be applied."

The Productivity Commission went on to add that:[578]

> "...the marginal benefit of intervening [through full regulation] decreases as the gap between the 'efficient price' and the 'monopoly price' narrows. Thus, for pipelines that are not exerting substantial market power (that is, where the price gap is narrow), the marginal benefit of intervening is lower."

The Productivity Commission's recommendation to allow a lighter handed form of regulation to be applied when the market power of a pipeline is constrained was echoed by the Expert Panel in its 2006 report to the MCE:[579]

> "The Panel's overall conclusion is that direct price or revenue controls should be applied principally to services supplied under conditions of natural monopoly and substantial market power. These conditions can be identified by having regard to the presence of economies of scale and scope, network externalities and other market characteristics which give rise to the presence of high barriers to entry by potential rivals. Less intrusive forms of regulation or no regulation at all are warranted where there is evidence of potential or actual competition sufficient to discipline the conduct of incumbent service providers and the barriers to entry are modest or low."

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576 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p. 228 and Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 51.

577 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p. 228.

578 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p. 332.

579 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p.51.

Further detail on the alternative forms of regulation that are provided for under the NGL and NGR is contained in Chapter 4.

D.3 Coverage, revocation and 15 year no-coverage decisions

A pipeline may become covered in one of four ways under the NGL:

- the pipeline was listed in Schedule A of the Gas Code as a covered pipeline;
- the relevant Minister is satisfied the pipeline meets **all** the coverage criteria in section 15 of the NGL (see Figure D.1);
- an unregulated pipeline voluntarily submits an access arrangement to the AER; or
- the pipeline is developed through a tender process approved by the AER.

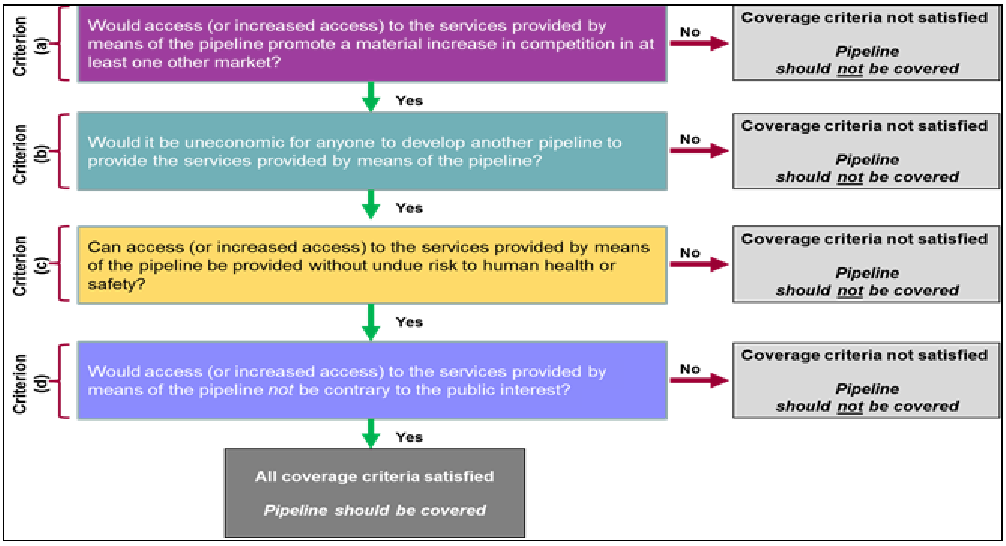
The NGL also provides for:

- coverage to be revoked if the relevant Minister finds that one or more of the coverage criteria are not satisfied; and
- a greenfields pipeline to become exempt from coverage for 15 years if the relevant Minister finds that one or more of the coverage criteria are not satisfied.

The remainder of this section provides further detail on the matters that the relevant Minister must consider when making a coverage, revocation of coverage or 15 year no-coverage decision.

It is worth noting that the NGL allows the coverage status of a pipeline and the form of regulation to change over time, because policy makers have recognised that circumstances can change over time.

Figure D.1 Coverage Criteria



D.3.1 Coverage and revocation of coverage decisions

An application for a coverage (or a revocation of coverage) determination can be made by any person to the NCC under section 92 of the NGL (or section 102 for revocation of coverage applications). Once such an application is received, the NCC is required to assess the application and make a recommendation to the relevant Minister.[580] In making its recommendation, the NCC is required to give effect to the following criteria set out in section 15 of the NGL:

- access (or increased access) to the services provided by means of the pipeline would promote a material increase in competition in at least one other market (criterion (a));
- it would be uneconomic to develop another pipeline to provide the services provided by means of the pipeline (criterion (b));
- access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety (criterion (c)); and
- access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest (criterion (d)).

In deciding whether or not these coverage criteria are satisfied, the NCC is required to have regard to the NGO.[581]

The decision-making framework in section 97(2) (or section 105(2) for revocation of coverage applications) of the NGL requires the NCC to recommend:

- coverage (or the continuation of coverage) if it is satisfied **all** the criteria are met; and
- against coverage (or the revocation of coverage) if it finds that one or more of the criteria is not satisfied.

A decision as to whether a pipeline should be covered (or coverage revoked) must ultimately be made by the relevant Minister having regard to the coverage criteria, the NGO, the NCC's recommendation and any submissions it receives. Like the NCC, the Minister can only determine the pipeline be covered if it is satisfied that **all** the coverage criteria are met.

With the exception of criterion (c), the coverage criteria in the NGL largely mirror the declaration criteria in sections Part IIIA of the CCA. The manner in which the

580 The identity of the 'relevant Minister' will depend on whether the pipeline is a transmission or distribution pipeline and if the pipeline crosses jurisdictions. For example, if the pipeline is a cross boundary transmission pipeline, the relevant Minister is the Commonwealth Minister but if the transmission pipeline is situated wholly within a jurisdiction, the relevant Minister will typically be the State or Territory Minister (the one exception is Queensland where the relevant Minister is the Commonwealth Minister). See definitions section of NGL.

581 Sections 97 and 105 of the NGL.

declaration criteria have been interpreted by the NCC, the Tribunal, Federal Court and High Court have therefore had a strong influence on the way in which the coverage criteria have been applied in gas. Further detail on how the coverage criteria and equivalent criteria in Part IIIA of the CCA have been interpreted and applied by these bodies is provided in Box D.4.

Box D.4 Interpretation of coverage and declaration criteria

Criterion (a)

Criterion (a) requires consideration to be given to whether access (or increased access) to services provided by means of the pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the pipeline. The application of this criterion has been described by the NCC and Tribunal as involving the following two stage assessment process:[582]

Stage 1: Identify economically separable dependent (upstream or downstream) markets; and

Stage 2: Assess whether access[583] (or increased access) is likely to promote a material increase in competition in the dependent market(s) identified in Stage 1.

In *Sydney Airport Corporation Limited v Australian Competition Tribunal* [2006], the Full Federal Court held that the second stage of this assessment process requires consideration to be given to whether the future state of competition in a dependent market(s) "with access" is likely to differ materially from the future state of competition "without access."[584] Whether or not competition in a dependent market is likely to be materially different in these two states of the world will depend on a range of factors, including:

- the current state of competition in the dependent market(s) – for example:
  - if the upstream or downstream market is already effectively competitive then access will not promote a material increase in competition in that market;[585] and
  - if there are other barriers to entry (unrelated to access) to the upstream or downstream market and these are prohibitive, then

582 NCC, Gas Guide – A guide to the functions and powers of the National Competition Council under the National Gas Law (Gas Guide), October 2013, pp. 28-39.

583 The term 'access' has been defined by the NCC, in its Gas Guide as a 'regulated right' to access the relevant services, rather than access that may be available under individual commercial arrangements.

584 *Sydney Airport Corporation Limited v Australian Competition Tribunal* [2006] FCAFC 146 [83]

585 *In the matter of Fortescue Metals Group Limited* [2010] ACompT 2 NCC, Gas Guide, October 2013, p. 34.

access is unlikely to promote a material increase in competition.[586]

- the ability and incentive the service provider has to exercise market power to adversely affect competition in the dependent market(s), by engaging in the following conduct:
  - preventing or hindering access;
  - raising prices above what would prevail in an effectively competitive market;
  - restricting throughput; and/or
  - reducing service quality.

If it is established that a service provider has no incentive and/or ability to exercise market power in the dependent markets, then access is unlikely to promote a material increase in competition.[587]

Some insight into the importance the NCC and the Tribunal have placed on the latter of these matters can be seen in the extracts below:

NCC Gas Guide[588]

> "The ability and incentive for a service provider to exercise market power to adversely affect competition in a dependent market is a necessary (although not sufficient) condition for access to promote competition. Prima facie, regulation of the terms and conditions of the provision of the service by the service provider in these circumstances is likely to promote competition.
>
> In addition, a finding that the service provider has the ability and incentive to exercise market power to adversely affect competition in a dependent market is likely to mean that the barriers to entry in that market result from the natural monopoly characteristics of the facility and its bottleneck position. In the usual case, this finding would mean that access would reduce barriers to entry and promote competition in that dependent market.
>
> By contrast, the service provider may not have the ability or incentive to exercise market power to adversely affect competition in the dependent market(s) where:
>
> (a) the facility does not occupy a bottleneck position in the supply chain for the service

586 NCC, Final Recommendation – Application for the revocation of coverage of the GGP under the National Gas Access Regime, November 2003, p. 98.

587 NCC, *Gas Guide*, October 2013, p. 35.

588 NCC, *Gas Guide*, October 2013, p. 36.

(b) the service provider is constrained from exercising market power in the dependent market(s), perhaps by competitive conditions in the dependent market(s) and/or the market power of other participants in the market(s), or

(c) the incentives faced by the service provider are such that its optimal strategy is to maximise competition in the dependent market(s). It may be profit maximising, for example, for a service provider to promote increased competition in the dependent market(s) and maximise demand for the services provided by its facility.

Access is unlikely to materially promote competition in the dependent market(s) if the service provider does not have the ability and incentive to exercise market power to adversely affect competition in the dependent market(s)."

Tribunal in *Re Duke Eastern Gas Pipeline Pty Ltd [2001]* ACompT2 [116-124]

"Whether competition will be promoted by coverage is critically dependent on whether EGP has power in the market for gas transmission which could be used to adversely affect competition in the upstream or downstream markets. There is no simple formula or mechanism for determining whether a market participant will have sufficient power to hinder competition. What is required is consideration of industry and market structure followed by a judgment on their effects on the promotion of competition.

There are strong commercial incentives for Duke to increase the throughput of the EGP, given its high capital cost, low operating costs and spare capacity. There are three pipelines which can supply gas to the market in Sydney, although lesser numbers to the ACT and other places in NSW. The three pipeline operators all stated that it was in their own financial interests to increase market share, and that this may involve undercutting the prices of other pipelines where that was financially justified. Gas producers have significant power in dealing with pipeline operators, as does AGL as the major gas purchaser in the Sydney and Canberra markets. There are alternatives to the use of the EGP for producers and for purchasers of gas which provide a countervailing influence on any attempted exertion of market power by EGP in the transport market. For example, in the case of the Gippsland Basin, gas can be transported to Sydney via the Interconnect or sold into the Victorian market, and in the case of purchasers of gas in Sydney, the Interconnect or the Cooper Basin/MSP can be used as alternatives to the EGP.

The existence of spare pipeline capacity over the next 10 to 15 years is a further factor which militates against EGP being able to exert market power to the detriment of competition in the upstream or downstream markets. If transmission prices were increased above competitive levels by EGP, the spare capacity could be used to defeat a price rise, particularly in the first half of the decade when the MSP and the Interconnect could supply all of the forecast increase in NSW/ACT demand with increases in pipeline capacity at relatively low cost. If there were constraints on gas supplies from Moomba, then the spare pipeline capacity may be ineffective in restraining EGP from increasing prices, but we have already concluded that this is not likely over the next 10 to 15 years.

...

The Tribunal concludes that EGP will not have sufficient market power to hinder competition based on the commercial imperatives it faces, the countervailing power of other market participants, the existence of spare pipeline capacity and the competition it faces from the MSP and the Interconnect. As EGP does not have market power, the Tribunal cannot be satisfied that coverage would promote competition in either the upstream or downstream markets."

Criterion (b)

Criterion (b) requires consideration to be given to whether it would be uneconomic for anyone to develop another pipeline to provide the services provided by means of the pipeline.

In 2012, the High Court in *Pilbara Infrastructure Pty Ltd v Australian Competition Tribunal*[589] held that the test to apply in considering whether it was uneconomic to duplicate particular infrastructure is a "privately profitable test" and that the term "uneconomic" should be interpreted as "unprofitable". The High Court went on to note the profitability of developing another facility will depend on whether a "person could reasonably expect to obtain a sufficient return on capital that would be employed in developing the facility". It also observed that if someone could develop an alternative facility as part of a larger project (e.g. as part of a mining project), "it would be necessary to consider the whole project in deciding whether the development of the alternative facility…would provide a sufficient rate of return".

The High Court's decision in this case overturned previous interpretations of this criterion, which had focused on whether the infrastructure exhibited natural monopoly characteristics. The practical effect of this interpretation is that if it can be established that it would be privately profitable for existing or future possible market participants to duplicate the asset, then criterion (b) would not be satisfied, even though duplication of the asset may not be economically efficient.

589 Pilbara Infrastructure Case (2012) 246 CLR 379, 413, [83 and 104].

Although the High Court's decision related to Part IIIA of the CCA, it has been applied by the NCC when considering coverage decisions in gas. For pipelines that are used by mining companies or other shippers that generate substantial profits, the High Court's interpretation has, in effect, raised the threshold for this criterion to be satisfied and, in so doing, made it more difficult for these pipelines to become covered.

Criterion (c)

Criterion (c) requires consideration to be given as to whether access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety. When applying this criterion, the NCC has stated it will generally presume that provisions within the regulatory regime will provide 'effective mechanisms to preserve human health and safety.'[590]

Criterion (d)

Criterion (d) requires consideration to be given to whether access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest.

In the Pilbara Infrastructure Case, the High Court found the matters the NCC and Minister may have regard to is "very wide indeed" and may include consideration of "matters of broad judgment of a generally political kind" as distinct from the other criteria, which are of a "more technical kind."[591]

Following this decision, the NCC has stated that its role under criterion (d) is not to conduct a detailed examination of the costs and benefits of access to be undertaken. Rather, its task is to "identify any matter that could mean access (or increased access) might be contrary to the public interest and then assess whether the likelihood and consequences of that matter lead to a conclusion that access is contrary to the public interest."[592] Elaborating further on this, NCC has noted the following:[593]

> "This criterion does not allow for coverage of a pipeline on 'public interest grounds' when any other coverage criterion is not satisfied; it can only operate to override coverage being available in situations where all other coverage criteria are satisfied."

590 NCC, Gas Guide, October 2013, p. 46.

591 Pilbara Infrastructure Case (2012) 246 CLR 379, 413, [42 and 44].

592 NCC, Gas Guide, October 2013, p. 48.

593 NCC, Final Recommendation – Application for the revocation of coverage of the Wagga Wagga Distribution Network, 8 August 2013, p. 25.

D.3.2 15 year no-coverage decisions

Under section 151 of the NGL, a service provider of a greenfield pipeline that is yet to be commissioned can apply to the NCC for a determination that exempts the pipeline from coverage for 15 years.

In a similar manner to the coverage provisions, the NCC is required to assess an application for a 15 year no-coverage decision having regard to the coverage criteria and the NGO and to make a recommendation to the relevant Minister.[594] If the NCC is satisfied that all the coverage criteria are met, the recommendation must be against a 15 year no-coverage decision. If, on the other hand, one or more criteria are not satisfied, the NCC's recommendation must be in favour of a 15 year no-coverage decision.[595]

Once the Minister has received the NCC's recommendation, it must decide itself whether to make a 15 year no-coverage determination, having regard to the coverage criteria, the NGO, the NCC's recommendation and any submissions it receives. Like the NCC, the Minister can only grant a 15 year no-coverage determination if it is satisfied that one or more coverage criteria are **not** met.[596]

D.3.3 Coverage related decisions

Table D.1 provides a summary of the key findings from some of the more significant coverage decisions that have been made over the last 15 years. As this table highlights, the decision as to whether a pipeline should be covered will depend on the specific facts surrounding the pipeline, its users and the markets it is used to supply, which, as the Dawson Valley Pipeline (DVP) example highlights, can change over time.

Some other interesting points to note from this table about the application of the coverage criteria are set out below:

- Criterion (a): In all but one of the cases where coverage has been revoked or a 15 year no-coverage determination has been granted, criterion (a) has **not** been satisfied.
- Criterion (b): Prior to the High Court's decision in the Pilbara Infrastructure case, this criterion was found to be satisfied in **all** determinations, but in the wake of this decision, the NCC and Commonwealth Minister have found it would be privately profitable to duplicate a number of pipelines (ie the LNG pipelines and DVP).
- Criterion (c): This criterion has been satisfied in all cases.

594 Section 154 of the NGL.

595 Section 154(2) of the NGL.

596 Section 157 of the NGL.

- Criterion (d): This criterion has been found to be satisfied in some cases but not in others. In most cases the finding on criterion (d) has been linked to the finding on criterion (a) (ie if there are no competition related benefits then the costs of coverage are likely to outweigh the benefits, which is contrary to the public interest).

Another important point to note from this table is that while it has been suggested that the Tribunal's decision not to cover the Eastern Gas Pipeline (EGP) resulted in access regulation being removed on other pipelines, the reasons cited by Tribunal in this case have not been repeated in any other coverage or revocation of coverage decisions. Each decision has instead been made by the relevant Minister on its merits having regard to the specific circumstances surrounding that pipeline. The fact that coverage has been revoked on so many pipelines reflects a more general trend under Part IIIA of the CCA for declaration (equivalent to coverage) to be used in a sparing manner. The reason for this is explored in further detail in the following section.

Table D.1 Findings in significant coverage, revocation of coverage and 15 year no-coverage determinations in eastern Australia

<table>
<tr><th>Pipeline</th><th>Year of Decision</th><th>Decision Maker</th><th>Decision</th><th colspan="2">Findings on Coverage Criteria</th></tr>
<tr><td rowspan="2">Eastern Gas Pipeline</td><td rowspan="2">2001</td><td rowspan="2">Tribunal (the Duke Decision)</td><td rowspan="2">Not to cover</td><td>Criterion (a) not satisfied.</td><td>Criteria (b)-(d) satisfied.</td></tr>
<tr><td colspan="2">Both the Minister and NCC were of the view that the EGP, which had recently been constructed should be covered. The Tribunal, on the other hand, found that criterion (a) was not satisfied because as a new entrant the EGP did not have sufficient market power to hinder competition in an upstream or downstream market and had a strong incentive to encourage use of the pipeline.</td></tr>
<tr><td rowspan="2">Moomba to Sydney Pipeline</td><td rowspan="2">2003</td><td rowspan="2">Commonwealth Minister</td><td rowspan="2">Revoke coverage between Moomba and Marsden (72% of pipeline length), retain coverage on remainder.</td><td>From Moomba to Marsden criterion (b) not satisfied, but all other criteria satisfied.</td><td>From Marsden to Sydney criteria (a)-(d) satisfied.</td></tr>
<tr><td colspan="2">The Minister did not follow the NCC’s recommendation, which was to retain coverage. The Minister instead found that criterion (b) was not satisfied between Moomba and Marsden and that coverage should be revoked on this part of the pipeline.</td></tr>
<tr><td rowspan="2">Moomba to Adelaide Pipeline System</td><td rowspan="2">2007</td><td rowspan="2">SA Minister</td><td rowspan="2">Revoke coverage</td><td>Criteria (a) and (d) not satisfied.</td><td>Criteria (b) and (c) satisfied.</td></tr>
<tr><td colspan="2">The NCC and Minister found that criterion (a) was not satisfied because access was unlikely to promote competition in any of the identified markets (ie, the upstream production market, the Adelaide gas sales market or the market for gas sales north of Adelaide). The NCC and Minster were also not satisfied that the overall benefit of regulated access would outweigh the costs and therefore found that criterion (d) was not satisfied.</td></tr>
</table>

Pipeline	Year of Decision	Decision Maker	Decision	Findings on Coverage Criteria	
QCLNG	2010	Commonwealth Minister	15 year no-coverage determination	Criteria (a) and (d) **not** satisfied.	Criterion (b) and (c) satisfied.
				The NCC and Minister found that access would not promote a material increase in competition in: the downstream LNG market because it was already competitive; the upstream gas production market because producers in the area could access other pipelines; or downstream gas sales markets in the Gladstone, Rockhampton and Wide Bay areas because users in this area have other supply options. Criterion (a) was therefore found not to be satisfied. In relation to criterion (d), the NCC noted that because access would not promote a material increase in competition in any market the costs of coverage were likely to outweigh the benefits and therefore be contrary to the public interest.	
APLNG	2012	Commonwealth Minister	15 year no-coverage determination	Criteria (a), (b) and (d) not satisfied.	Criterion (c) satisfied.
				The NCC and Minister's reasons for finding that criteria (a) and (d) were not satisfied were essentially the same as those cited in the QCLNG case. Criterion (b) was also found not to be satisfied in this case. In forming this view, the NCC and Minister pointed to the fact that there were three LNG pipelines being developed in the region and noted that this indicated it was economically feasible to develop an alternative pipeline. Note that the decision on criterion (b) followed the High Court's decision on this criterion.	
GLNG	2013	Commonwealth Minister	15 year no-coverage determination	Criteria (a), (b) and (d) **not** satisfied	Criterion (c) satisfied.
				The NCC's and Minister's reasoning in this case is essentially the same as it was in the APLNG case.	
South East Pipeline System	2013	SA Minister	Not to cover	Criteria (a) and (d) **not** satisfied	Criterion (b) and (c) satisfied.

Pipeline	Year of Decision	Decision Maker	Decision	Findings on Coverage Criteria	
				The NCC and Minister were not satisfied that access would promote a material increase in competition in any of the dependent markets identified (the Australian and global markets for paper tissue products, upstream gas supply/production in the Katnook area and other shippers delivering gas to Katnook via the SEA Gas and SESA pipelines, a downstream market for industrial, commercial and domestic purposes in the South East region of SA). In relation to criterion (d), the NCC noted that because access would not promote a material increase in competition in any market the costs of coverage were likely to outweigh the benefits and therefore be contrary to the public interest.	
Wagga Wagga Distribution System	2014	NSW Minister	Revoke coverage	Criterion (a) **not** satisfied if retail price regulation retained	Criterion (b), (c) and (d) satisfied
				The NCC found that access would not promote a material increase in competition in the eastern Australian wholesale gas market or the market for transmission services, but that it may promote a material increase in competition in the downstream gas sales market if retail price regulation was removed (note that the NCC found that limited competition had emerged in the downstream gas sales market because of the presence of retail price regulation, which was limiting available margins). The NCC went on to note however that if retail price regulation was not removed, then competition in this market was likely to remain stagnant irrespective of whether the pipeline was covered or not and criterion (a) was unlikely therefore to be satisfied under this scenario. Following a decision by the NSW Government in early 2014 not to remove retail price regulation on gas sales to small customers, the NSW Minister concluded that criterion (a) was not satisfied and that coverage should be revoked.	
Dawson Valley Pipeline (DVP)	2014	Commonwealth Minister	Revoke coverage	Criteria (a) and (b) **not** satisfied.	Criteria (c) and (d) satisfied.

Pipeline	Year of Decision	Decision Maker	Decision	Findings on Coverage Criteria
				The NCC and Minister found that: • Criterion (a) was not satisfied because there would only be a small amount of capacity available to third parties from 2015, so access would not promote a material increase in competition in any market. • Criterion (b) was not satisfied because there was evidence that one of the users of the pipeline was intending to develop its own pipeline to supply its plant. This was the fourth time that the coverage status of the DVP has changed over the last 17 years, ie: • the DVP was originally identified as a covered pipeline in Schedule A of the Gas Code; • in mid-2000 coverage was revoked because criterion (a) was found not to be satisfied; and • in 2006 coverage was reinstated because all the coverage criteria were found to be satisfied.

D.3.4 Recent reviews of Part IIIA and potential implications for the coverage criteria

Following the High Court's decision in the Pilbara Infrastructure case a number of parties questioned whether the declaration criteria in Part IIIA, and by extension the coverage criteria in the NGL, were operating as they were intended to.

This question was considered in some detail by the Productivity Commission in its 2013 review of the National Access Regime. In short, the Productivity Commission found that while the declaration has been rare, this was consistent with Hilmer Committee's intention that the regime be used sparingly. The Productivity Commission went on to note that the rarity of declaration did not mean the regime had been unsuccessful, because it could be the case that:[597]

> "...parties are resolving access disputes without recourse to Part IIIA, or that Part IIIA is an effective threat that encourages parties to reach private settlement."

Some of the other key findings and observations from this review are outlined below:

- The National Access Regime should be retained and used to address "an enduring lack of effective competition, due to natural monopoly, in markets for infrastructure services where access is required for third parties to compete effectively in dependent markets" and the service provider has an ability and incentive to exercise market power. The Productivity Commission went on to note that this is the only economic problem that access regulation should address and that it should not be viewed as a vehicle to avoid the duplication of infrastructure, or wider social and economic issues;[598]
- The scope of the National Access Regime should be "confined to ensure its use is limited to the exceptional cases where the benefits arising from increased competition in dependent markets are likely to outweigh the costs of regulated third party access to infrastructure services;"[599]
- Competition between service providers will generally be preferable to access regulation where two or more service providers are able to provide the same service (or an effective substitute service). Even if an infrastructure service provider has a monopoly position in a particular market, its market power might be constrained by the existence of substitutes, countervailing market power or the threat of entry;[600]

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597 Productivity Commission, *National Access Regime*, 25 October 2013, p. 14.

598 Productivity Commission, *National Access Regime*, 25 October 2013, p. 2.

599 ibid.

600 Productivity Commission, *National Access Regime*, 25 October 2013, p. 8.

- The declaration criteria should be amended in the following ways to ensure that they target the relevant economic problem;[601]
  - Criterion (a) should be amended so that it will only be satisfied where access on reasonable terms and conditions through *declaration* (rather than access per se) would promote a material increase in competition in a dependent market;[602]
  - Criterion (b) should be amended so that it can be used to identify facilities that give rise to an enduring lack of effective competition.
  - Criterion (f) (or criterion (d) in the coverage criteria) should be amended so that the test is expressed in the affirmative (ie access would need to promote the public interest rather than being 'not contrary to' the public interest).

The Productivity Commission's observation that the third-party access regime should be confined to exceptional cases was endorsed by the Competition Policy Review Panel as highlighted in the following extract:[603]

> "The bottleneck infrastructure identified by the Hilmer Review included electricity wires, gas pipelines, telecommunication lines, freight rail networks, airports and ports. Distinct access regimes have emerged for these different types of infrastructure, reflecting their distinct physical, technical and economic characteristics. Those regimes appear to be achieving the original policy goals identified by the Hilmer Review. Part IIIA has played an important role in developing these access regimes.
>
> ...
>
> Part IIIA should continue to provide a back stop to the current industry-specific access regimes...
>
> The Panel agrees with the conclusion of the recent PC inquiry that the National Access Regime is likely to generate net benefits to the community, but its scope should be confined to ensure its use is limited to the exceptional cases where the benefits arising from increased competition in dependent markets are likely to outweigh the costs of regulated third-party access."

601 Productivity Commission, *National Access Regime*, 25 October 2013, pp. 16-20.

602 The Productivity Commission noted that this criterion would not be satisfied where: there is already effective competition in dependent markets (ie because it would not promote a material increase in competition in this market); or access is already granted to all third parties on reasonable terms and conditions (ie because declaration would not be expected to change the terms and conditions of access).

603 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review Final Report*, March 2015, p. 431.

The Competition Policy Review Panel also suggested that the declaration criteria be amended as follows:[604]

- Criterion (a) should require that access on reasonable terms and conditions through declaration promote a substantial increase in competition in a dependent market that is nationally significant. Elaborating further on this proposed change, the Panel stated:[605]

  > "The burdens of access regulation should not be imposed on the operations of a facility unless access is expected to produce efficiency gains from competition that are significant. This requires that competition be increased in a market that is significant and that the increase in competition be substantial."

- Criterion (b) should require that it be uneconomic for anyone (other than the service provider) to develop another facility to provide the service. The Panel in this case endorsed the use of the privately profitable test adopted by the High Court.
- Criterion (f) should require that access on reasonable terms and conditions through declaration promote the public interest.

The Competition Policy Review Panel also made the following observations about the circumstances in which access regulation should be applied:[606]

> "The Regime facilitates intrusive economic regulation of infrastructure assets. It overrides private property rights, mandating that the operator of an infrastructure facility make that facility available for use by a third-party on terms and conditions (including price) determined by a regulatory body (the ACCC). By that process, the economic return that the operator of the facility is able to earn on its investment in the facility will be subject to regulation.
>
> Economic regulation of privately owned assets is likely to impose costs on the economy. In recommending the introduction of the Regime, the Hilmer Review was conscious of the economic costs that might be imposed:
>
> *The Committee is conscious of the need to carefully limit the circumstances in which one business is required by law to make its facilities available to another. Failure to provide appropriate protection to the owners of such facilities has the potential to undermine incentives for investment. Nevertheless, there are some industries where there is a strong public interest in ensuring that effective competition can take place ...*
>
> The Productivity Commission also noted the costs that are created by economic regulation:

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604 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review Final Report*, March 2015, p. 74.

605 ibid, p. 73.

606 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review , Draft Report*, September 2014, pp. 264-265.

Access regulation also imposes costs, in particular where it adversely affects incentives for investment in markets for infrastructure services. There are costs associated with errors in setting access prices. For example, when prices are set too low, this can lead to delayed investment in infrastructure, or the non-provision of some infrastructure services.

Regulated third party access can also impose costs on infrastructure service providers from coordinating multiple users of their facilities.

Given the economic costs that are likely to be caused by this form of regulation, it is important to examine carefully the benefits of the Regime and to ask whether those benefits can be achieved by a less intrusive form of regulation."

The findings of both the Productivity Commission and the Competition Policy Review Panel suggest that while some amendments may be made to the coverage criteria to bring them into line with any changes that are made to the declaration criteria, the threshold for coverage will still be high (if not higher if criterion (a) is amended to require a substantial increase in competition) and will continue to be applied in a sparing manner.

D.4 Alternative forms of regulation under the NGL and NGR

A covered pipeline may be subject to either full or light regulation, depending on the degree of market power it possesses. The circumstances in which policy makers expected light regulation to be applied can be found in the following extract taken from the Second Reading Speech:[607]

"Determining how covered pipeline services are to be regulated requires an assessment of the potential for market power to be exploited by a service provider. …where light regulation can reduce the costs of regulation while still providing an effective check on a pipeline's market power, the light regulation option should be available..."

Further insight into the circumstances in which light regulation is intended to apply can be found in the following extract taken from the NCC's Light Regulation Guide:[608]

"The intention in introducing this lighter form of regulation is that, through its use in appropriate circumstances, the administrative costs to the pipeline services provider and the regulator will be lower. This less intrusive form of regulation is considered to be appropriate where the market power exercised by the provider is less substantial and there is the potential for contestability for the services to emerge. It may also be appropriate where the number of access seekers is relatively small and

607 South Australian Hansard 2008, '*National Gas (South Australia) Bill 2008*', Legislative Assembly, p. 2701, 9 April 2008.

608 NCC, Light regulation of covered pipeline services – A guide to the function and powers of the NCC under the NGL Part C, July 2011, p. 14.

these parties can themselves exercise some countervailing market power in the course of commercial negotiations. Further, light regulation may be an appropriate option for regulation where particular assets are in a transition towards effective competition."

A snapshot of the obligations that service providers of full and light regulation pipelines are subject to under the NGL and NGR is provided in the table below. This table also sets out the obligations that unregulated pipelines are subject to under the NGL and NGR.

Table D.2 Economic regulatory and information obligations for full, light and unregulated pipelines

		Full Regulation	Light Regulation	Unregulated
Application of the Economic Regulatory Provisions in the NGR and NGL				
Obligation for pipeline service provider to:	• obtain AER approval for proposed reference tariffs and other conditions of access[609]	✓	×	×
	• publish prices and other terms and conditions of access[610]	Access arrangement must be made available	Must be published on the service provider's website	×
	• report to the AER on the status of access negotiations[611]	×	✓	×
	• comply with facilitation of, and request for, access rules[612]	✓	✓	×
	• not engage in price discrimination unless it is efficient to do so	×	✓	×
	• comply with other NGL provisions that are designed to prevent service providers from engaging in conduct that may adversely affect 3rd party access or competition.[613]	✓	✓	×
Access to dispute resolution mechanism in NGL[614]		✓	✓	×

609 Rule 48 of the NGR.

610 Rule 36 of the NGR for light regulation and rule 44 for full regulation.

611 Rule 37 of the NGR.

612 Part 11 of the NGR.

613 Section 133 of the NGL

614 Chapter 6, Part 1 of the NGL and Part 12 of the NGR.

	Full Regulation	Light Regulation	Unregulated
Bulletin Board and STTM Provisions in the NGR and NGL			
Obligation to provide AEMO with information for the BB[615]	Yes if the service provider is designated by AEMO as a BB facility operator.		
Obligation to provide AEMO with any information it requires for the operation and administration of a STTM[616]	✓	✓	✓

Further detail on these obligations is provided below, along with an overview of the matters the NCC is required to consider when making a decision on the form of regulation.

D.4.1 Full regulation

The service provider of a pipeline that is subject to full regulation is required by the NGR to periodically submit a 'full access arrangement' (AA) to the AER (or the Economic Regulatory Authority (ERA) in Western Australia) and obtain its approval for the proposed terms and conditions of access to the reference service(s). In accordance with rule 48 of the NGR, the full AA must set out:

- the reference service(s) to be provided by the pipeline and the reference tariff payable for each reference service (a 'reference service' is defined in the NGR as a service that is likely to be sought by a significant portion of the market);
- the terms and conditions upon which the reference service(s) will be provided; and
- the pipeline's queuing policy,[617] capacity trading policy,[618]extensions and expansions policy[619]and the terms on which receipt/delivery points may be changed by the shipper.

When assessing a proposed access arrangement, the AER is required to have regard to:

615 Section 223 of the NGL.

616 Section 91FEA of the NGL.

617 This policy is used to determine the order of priority for access to spare and developable capacity.

618 The capacity trading policy must enable users to transfer capacity and comply with the following: a user may transfer any portion of its contracted capacity to a third party through a sub-contractual arrangement without the service provider's consent but must inform the service provider of the sub-contract and the likely duration, the identity of the third party and the amount of capacity transferred; and a user may transfer any portion of its contracted capacity to a third party with the service provider's consent. The service provider must not withhold consent unless it has reasonable grounds for doing so.

619 The extensions and expansions policy must set out whether the applicable access arrangement will apply to incremental services to be provided as a result of a particular extension to, or expansion of, the pipeline or may allow for later resolution of that question on a basis stated in the requirements.

- the price and revenue regulation related provisions set out in Part 9 of the NGR;
- the national gas objective (NGO) set out in section 23 of the NGL; and
- the revenue and pricing principles set out in section 24 of the NGL.

To ensure that users (existing or prospective users) have some degree of protection if they decide to negotiate access to an alternative service or different terms and conditions (including tariffs), provision has been made in the NGL for a user or a service provider to trigger the dispute resolution mechanism if a dispute about access arises.[620] The dispute resolution body in eastern Australia and the Northern Territory is the AER, while in WA it is the ERA.[621]

Some other important safeguards that have been included in the NGL and NGR to facilitate access and to prevent service providers from engaging in conduct that may adversely affect third party access or competition in upstream or downstream markets include:

- The facilitation of, and request for, access rules set out in Part 11 of the NGR. Amongst other things, these provisions require service providers to:
  - make available information that a prospective user reasonably requires to decide whether to seek access to a pipeline service; and
  - respond to any access request made by a prospective user within a defined period and provide information on the tariff that would apply, if it is commercially and technically feasible to provide the service.
- Section 133 of the NGL, which states that a service provider must not engage in conduct that prevents or hinders a person's access to the services provided by the pipeline.
- Sections 137-148, which set out the ring-fencing requirements that a service provider must comply with and are designed to prevent a service provider from:
  - carrying on a related business (ie production, purchase or sale of natural gas); and
  - conferring an unfair advantage on an associate that takes part in a related business.

These safeguards apply equally to pipelines that are subject to full and light regulation.

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620 If such a dispute arises, the prospective user or service provider may notify the dispute resolution body in writing. The dispute resolution body may then require the parties to mediate, conciliate or engage in other alternative dispute resolution processes to resolve the dispute.

621 The dispute resolution mechanism has not yet been triggered on any light or full regulation pipelines.

D.4.2 Light regulation

In contrast to full regulation, light regulation places greater emphasis on commercial negotiation and information disclosure. Users and prospective users are also provided with some degree of protection in these negotiations through the following safeguards:

- the dispute resolution mechanism in Chapter 6 of the NGL and Chapter 12 of the NGR;
- section 136 of the NGL, which prohibits a service provider of light regulation services from engaging in price discrimination, unless it is efficient to do so; and
- sections 133 and 137-148 of the NGL, which are designed to prevent service providers from engaging in conduct that may adversely affect third party access or competition in other markets.

Commercial negotiation and information disclosure are encouraged through a number of provisions in the NGR, which require a service provider to:

- publish the price and non-price terms and conditions of access to light regulation services on its website (rule 36);
- comply with the facilitation of, and request for, access rules (Part 11 of the NGR); and
- report to the AER on access negotiations (at least annually) and, in doing so, set out the results of the negotiations and provide any other information that the AER requires (rule 37).

The service provider of a light regulation pipeline also has the option under section 116 of the NGL to develop a 'limited' AA for approval by the AER. The key difference between a limited and full AA is that the limited AA does not need to include reference tariffs.

The AER's (ERA's) role under this form of regulation is to monitor the progress of access negotiations and arbitrate any access disputes that may arise.

D.4.3 Unregulated pipelines

Unregulated pipelines are not subject to any form of economic regulation under the NGL or the NGR. Nor are they required by the NGL to provide access to third parties on fair and reasonable terms, or in a non-discriminatory manner. They may, however, still be required to provide AEMO with:

- certain information for publication on the Bulletin Board if they have been deemed a Bulletin Board facility operator;[622] and

622 Section 223 of the NGL.

- any information it requires for the operation and administration of a STTM, if it is in control of such information.[623][624]

The obligation to provide this information has been established through the NGL. Provision has also been made in the NGR for the costs incurred in the provision of aggregation and information services to be invoiced to AEMO and for the AER to assess the reasonableness of these costs before the invoice is paid.[625]

D.4.4 Form of regulation decisions by the NCC

For pipelines that are covered and are not 'designated,'[626] an application may be made to the NCC seeking a change in the form of regulation to apply to that pipeline. Unlike a decision on coverage, which must be made by the relevant Minister, a decision as to whether full or light regulation should be applied can be made by the NCC.

In making such a decision, the NCC is required by section 122 of the NGL to have regard to:

(a) the likely effectiveness of full and light regulation in promoting access to the services provided by the pipeline that is the subject of the application; and

(b) the effect of full and light regulation on the costs that may be incurred by an efficient service provider, efficient users and prospective users, and end-users.

In doing so, the NCC is required to have regard to the NGO, the form of regulation factors in section 16 of the NGL and any other matters the NCC considers relevant.

In simple terms, the form of regulation factors require consideration to be given to the extent to which:

- the service provider is likely to possess market power, either as a result of barriers to entry or network externalities;
- any market power possessed by the service provider may be constrained by:
  - countervailing power held by users or prospective users; or
  - the ability of users or prospective users to switch to an alternative provider of pipeline services or another energy source; and
- users or prospective users will have access to adequate information to negotiate on an informed basis under light regulation.

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623 Section 91FEA of the NGL

624 This obligation is more relevant to pipelines that are connected directly to a STTM.

625 Rules 197-198.

626 A designated pipeline is a pipeline classified by the Regulations, or designated in the application Act of a participating jurisdiction, that cannot be subject to light regulation. The pipelines that are currently designated include AGNL's SA Distribution Network, ATCO's Western Australian gas distribution system, the three Victorian gas distribution systems and the DTS. See National Gas (South Australia) Regulations 2009, National Gas Access (WA) (Part 3) Regulations 2009, Schedule 1 and Victorian Government Gazette No. S222m, 30 June 2009.

E Operation of the STTM

This appendix provides a detailed overview of the STTM design and operation. It draws on AEMO's Industry Guide to the STTM v3.5 and sets out:

- history and policy objectives of the STTM;
- design and structure of the market;
- rule changes carried out by the AEMC to date; and
- current market participants at each of the STTM hubs.

E.1 History and policy objectives

The STTM was implemented in Adelaide and Sydney in September 2010 and in Brisbane in December 2011. It was part of a package of reforms by the Council of Australian Governments' (COAG) Ministerial Council on Energy (MCE), which also included the National Gas Bulletin Board, Gas Statement of Opportunities and the establishment of a national gas market operator.[627]

At its November 2005 meeting, the MCE agreed to an industry-led approach to gas market development and established the Gas Market Leaders Group. This group, which comprised members from all aspects of the natural gas supply chain, was required to further develop options identified in a 2005 report by the Allen Consulting Group prepared for the MCE.[628]

Recommendations put forward by the Gas Market Leaders Group were required to be consistent with the following MCE principles:[629]

- Information on market and system operations and capabilities at all stages of the gas supply chain (subject to recognition of existing contractual confidentialities) should be publicly available and frequently updated.
- Gas market structure should facilitate a competitive market in all sectors.
- Gas market participants should be able to freely trade between pipelines, regions and basins.
- There should be regulatory certainty and consistency across all jurisdictions.

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627 The national gas market operator became AEMO, which assumed the functions of the state-based Gas Market Company, Retail Energy Market Company and gas functions of the Victorian Energy Networks Corporation.

628 The Allen Consulting Group, *Options for the development of the Australian Wholesale Gas Market*, Final Report, June 2005.

629 Gas Market Leaders Group, *National Gas Market Development Plan – Gas Market Leaders Group report to the Ministerial Council on Energy*, June 2006, p. 1.

- Market design and institutional requirements should be responsive to and reflective of the needs of the market and market participants.

The Gas Market Leaders Group presented its report to the MCE for consideration in June 2006. Among other things, the group recommended that the "detailed design of a Short-Term Trading Market be progressed for all states, except Victoria".[630]

In recommending the establishment of the STTM, the Gas Market Leaders Group set out the following objectives for the market:[631]

- Establish a mandatory price-based balancing mechanism for gas delivered and withdrawn from defined market hubs, replacing existing gas balancing arrangements at delivery points within hubs.

- Facilitate gas trading on a daily basis at market driven short-term prices.

- Provide pricing signals and facilitate secondary trading between shippers and users, for gas-fired generators, for trading over interconnecting pipelines between hubs, and to facilitate greater demand side response.

STTM costs and benefits were assessed by consultants MMA on behalf of the Gas Market Leaders Group. In 2006, MMA estimated the set up costs for hubs in Sydney and Adelaide would be $9 million, with ongoing operating costs of around $1.6 million annually. The net benefit of the STTM over the first 10 years of operation was estimated at $31 million due to:[632]

- more efficient pricing: through transparency around the short term price of gas;

- the value of short term trading: enabling mutually beneficial trading to occur more regularly;

- improved gas allocation during a shortfall: ensuring scarce gas is allocated to the highest value users;

- improved capacity utilisation: through more efficient investment in pipeline capacity; and

- other benefits, including: improved risk management allocation, provision of additional investment signals and greater flexibility for gas-fired generators.

Since the inception of the STTM in 2010, the AEMC has considered 11 changes to the relevant NGR, all of which have been submitted by AEMO. A summary of these is set out in section E.3.

The following section provides an overview of the design and operation of the STTM, including number and type of participants.

630 ibid, p. 2.

631 ibid, p. 23.

E.2 Design and structure of the STTM

The STTM was designed as a day-ahead or ex ante market for the trade of wholesale gas at the point of entry to distribution networks.[633] They are used for:

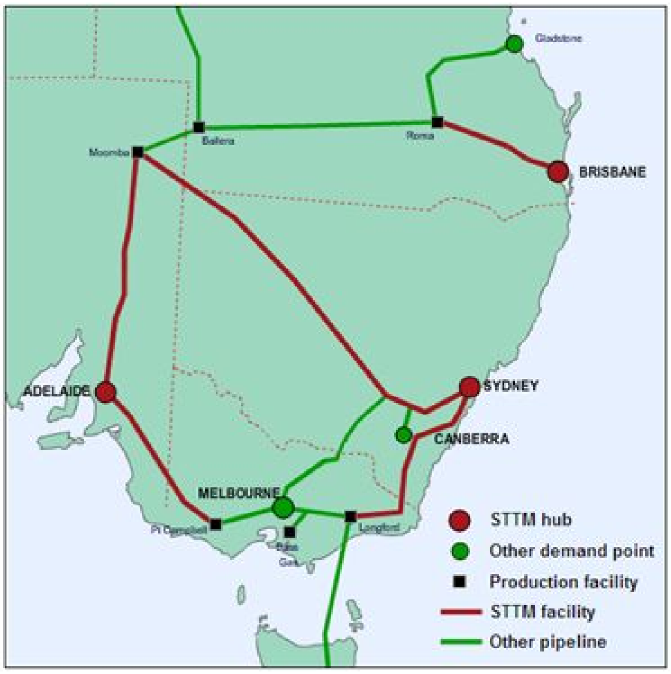
1. providing a competitive service for participants to manage their daily gas imbalances; and

2. commodity trading.

Prior to the implementation of the STTM, commodity trading occurred bilaterally between participants and balancing was generally undertaken through contractual arrangements with pipeline operators or organised 'Swing Service' markets, such as what used to occur in Adelaide and under the current arrangements in south-west Western Australia.[634]

STTM hubs in Adelaide and Sydney are each supplied by two transmission pipelines, while the Brisbane STTM hub is supplied by one transmission pipeline, as shown in Figure E.1.

Figure E.1 STTM hubs are located at Adelaide, Brisbane and Sydney



Source: AEMO.

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632 ibid, pp. 38-39.

633 Ex ante refers to transactions that occur the day before a commodity is traded.

634 AEMO and REMCo, *Business Case for a Short Term Trading Market in Western Australia*, available at: http://www.remco.net.au/attachments/article/60/WA%20STTM%20Assessment%20-%20Final%20%2826-06-13%29%20v6.pdf

A range of participants, such as retailers, gas-fired generators and large industrial customers, use the STTM. All participants all use the market to physically sell or procure gas and there are no financial organisations registered. Section E.4 sets out the number and type of participants currently registered at each hub.

Trades on the STTM can be categorised as:

- ex ante within participant - gas traded between the same entity;
- ex ante - gas traded between different entities; and
- ex post deviation - balancing deviations during the gas day.

Due to the physical characteristics of natural gas and the time it takes to flow through transmission pipelines, nominations by gas users are made to producers and pipeline operators a day ahead.[635] Accordingly, the STTM design consists of two broad elements:

- **the ex ante or commodity market** – where supply and demand is matched for the following day and an ex ante price determined by the market operator; and
- **on-the-day balancing mechanism** – to account for differences during the gas day between the supply and demand schedules determined in the ex ante market and to ensure system security is maintained.[636]

Each of these elements is discussed below in sections E.2.2 and E.2.3. Before this, we briefly describe how the STTM design accounts for the contractual arrangements that underpin the contract carriage pipeline framework.

E.2.1 STTM overlay on the contract carriage pipeline framework

The underlying contractual arrangements between transmission pipeline operators and shippers, and between distribution networks and users, must be registered in the STTM with AEMO.[637] Preservation of these arrangements was a key design feature of the market and, while AEMO operates the market, it has no role in how transmission pipelines, storage facilities, production facilities or distribution networks are operated and scheduled.

Every bid to buy gas and every offer to sell gas through the STTM must be associated with a trading right. AEMO requires shippers and users to hold trading rights with sufficient pipeline capacity for the quantities of gas they are scheduled to flow.

635 In Victoria, gas is typically produced and delivered within 6–8 hours due to the close proximity of the gas fields to demand centres. In contrast, gas delivered from the Cooper Basin into Sydney can take 2-3 days.

636 In this context, system security refers to transmission and distribution pipelines operating within their pressure tolerances.

637 The STTM design preserves the fundamental contract carriage arrangements on which the industry is based. Detail on the contract carriage arrangements can be found in Chapter 4.

When pipelines are scheduled, the terms of haulage contracts usually give shippers with firm gas haulage rights priority over shippers with lesser priority haulage rights, such as contracts with a non-firm or as-available capacity. However, the STTM scheduling process does not take account of these priorities when scheduling offers other than to resolve tied offer prices.[638]

If a pipeline's capacity is constrained, an as-available shipper can theoretically displace a firm capacity shipper in the STTM by offering gas at a lower price. This prevents the firm capacity shipper from using the pipeline capacity that it has funded.[639]

On a constrained pipeline, if an as-available shipper has been scheduled by the pipeline operator to flow gas to the hub, and, in doing so, has prevented a shipper with firm pipeline haulage rights from shipping gas on the same pipeline, then the as-available shipper pays a capacity charge based on the actual quantity of gas flowed.[640]

The firm-capacity shipper who is displaced on that pipeline receives a capacity payment based on the amount of gas it offered into the ex ante market but did not flow.

E.2.2 Ex ante (commodity) market

The ex ante or commodity market is where shippers offer to supply gas and users bid to purchase gas that will flow the following day. Offers and bids can be submitted to AEMO up until 12.00pm the day before gas day in Adelaide and Sydney, and up until 1.30pm in Brisbane.[641]

Transactions in the ex ante market can be separated into two categories. The first and most common relates to the same entity selling and purchasing gas through the hub. As all gas that flows through the distribution network within the hub must be transacted in the STTM, participants with underlying long term contracts that do not need to trade at the hub on an ex ante basis must still participate. This generally results ina retailer offering gas into the STTM and bidding to withdraw the same amount.

In this instance, as a participant is on both sides of the transaction, there is no price risk in the ex ante market. For instance, if the retailer’s underlying gas contract price is $3/GJ but the STTM clears at $7/GJ, the retailer will effectively be selling and buying the gas to itself at $7/GJ in the STTM. Price risks emerge through the on-the-day balancing mechanism if a retailer deviates from its ex ante schedules on the gas day, as discussed in section E.2.4.

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638 AEMO, *Industry Guide to the STTM*, December 2014, p. 27.

639 ibid.

640 ibid, p. 28.

641 The variation in timing is due to differences in gas day start times at the hubs. The Brisbane hub operates from 8am EST while Sydney and Adelaide operate from 6.30am EST.

The second category of transaction is where two different entities buy and sell gas in the ex ante market. A retailer who has expected demand at the hub of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ in the ex ante market and bid to withdraw 100 TJ. In this example, the retailer will be exposed to ex ante price risk on 20 TJ, which is the volume of gas not supplied through the long term contract.

STTM bids and offers can include up to 10 price-quantity steps. Offers to supply are given in increasing price order with increasing cumulative quantities. Bids to buy are given in decreasing price order with increasing cumulative quantities, as illustrated in Table E.1.[642]

Prices in the STTM must be within $0/GJ to $400/GJ, although users can submit price taker bids that represent a quantity of gas the user will accept at any price.[643] If the cumulative price over seven consecutive days reaches $440/GJ,[644] AEMO applies the administered price cap of $40/GJ for the whole of the gas day it is determined.[645] This mechanism is designed to protect participants from uncontrollable risks due to sustained high prices.

Table E.1 STTM offers and bids are in increasing and decreasing price order, respectively

Price steps	Offers to ship gas to the hub		Bids to withdraw gas from the hub	
	Price ($)	Quantity (GJ)	Price ($)	Quantity (GJ)
1	0	5,000	[price taker]	10,000
2	1	20,000	8	1,000
3	1.5	10,000	5	5,000
4	2	5,000	3.5	2,000
5	3	20,000	1	1,000

Source: AEMC, based on AEMO STTM training material.

AEMO produces the market schedules and prices using an algorithm on the day before the gas day. The ex ante price is determined by stacking offers from lowest to highest price against bids to purchase gas from highest to lowest price, as shown in Figure E.2.

The point where demand intersects supply represents the marginal cost at which demand from all distribution systems is met by supply from shippers on STTM

642 AEMO, *Industry Guide to the STTM*, December 2014, p. 30.

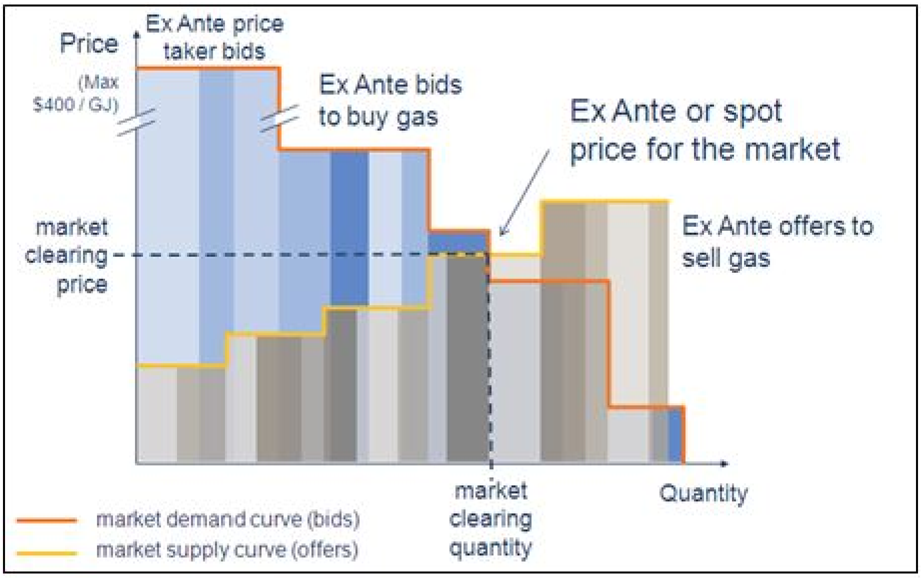
643 A price taker bid quantity is represented by a blank price cell in a price-quantity pair.

644 NGR, rule 364, CPT horizon.

645 NGR, rule 428(6)(a).

transmission pipelines and other hub facilities. All of the gas that flows in accordance with the ex ante market schedule on the gas day is settled at the ex ante price.

Figure E.2 The ex ante market price is set where demand meets supply



Source: AEMO, *An Overview of the Short Term Trading Market (STTM)*, Section 4, p. 15.

In situations where bids (including price-taker withdrawals) or offers have the same price and the total quantity bid or offered cannot be scheduled, then tie-breaking rules are applied to determine the schedule.

During this scheduling process, one or more pipelines might reach their hub capacity—the pipeline is then said to be capacity constrained. If demand at the hub has not been met when a pipeline becomes constrained, the scheduling process continues as before, but offers are only considered from unconstrained facilities. Demand can be satisfied from any STTM transmission pipeline or other facility subject to its physical capacity on the gas day.[646]

After the ex ante market schedules are published, shippers make nominations to pipeline operators in accordance with their relevant contracts. This process is not part of the STTM and there is no requirement for pipeline nominations to match the quantities scheduled in the market. Similarly, the STTM has no involvement in any distribution network processes for managing the scheduling of withdrawals from a hub. If nominations differ from the STTM ex ante schedules, this is dealt with through the on-the-day balancing mechanism, which is discussed below.

Figure E.3 shows the timeline for a typical STTM day in Adelaide and Sydney in Eastern Standard Time.[647]

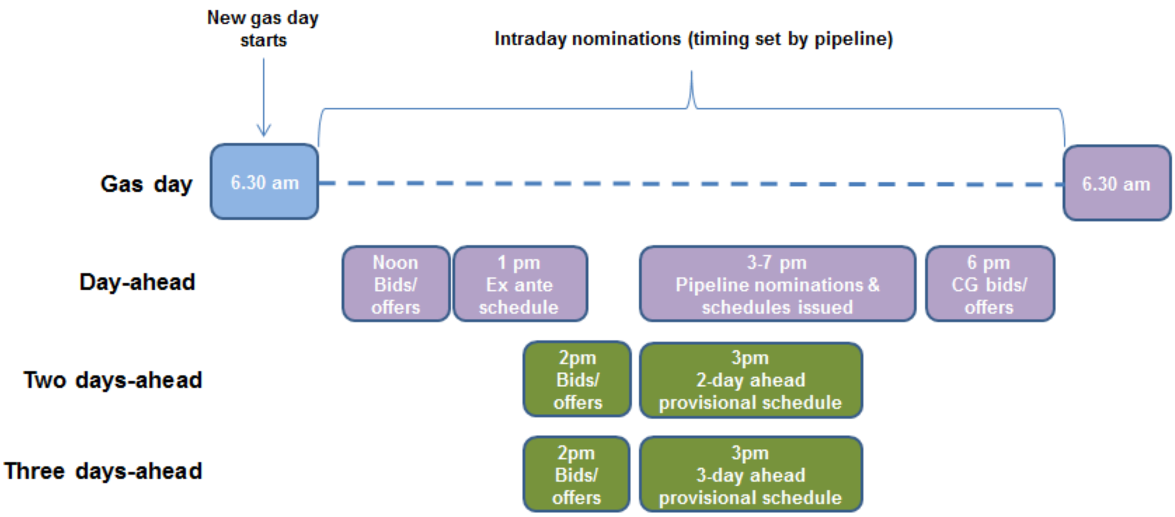
646 AEMO, Industry Guide to the STTM, December 2014, p. 33.

647 Timings for the Brisbane STTM are 1.5 hours after Adelaide and Sydney.

Two and three days before the gas day, AEMO publishes provisional schedules, giving participants a three-day outlook for estimated supply and demand at each hub. The day before gas is to flow, shippers and users must submit their bids and offers to AEMO by 12.00pm. At 1.00pm AEMO issues the ex ante market schedule for the following day.

Between 3.00pm and 7.00pm participants submit their nominations to the pipeline operators for the next day and the schedules are issued by the pipeline operator.[648] The gas day starts at 6.30am the following morning. During the gas day, and in accordance with renomination processes, shippers and users are able to request intraday nominations to the pipeline operator.

Figure E.3 Adelaide and Sydney STTM timeline



Source: AEMC, based on AEMO Industry Guide to the STTM v3.5 and AEMO STTM training material.

E.2.3 On-the-day balancing mechanism

The on-the-day balancing mechanism is the second design element of the STTM and the primary role of the market in the broader east coast framework. Without the STTM or other form of balancing market, pipeline operators would balance the system under a service negotiated as part of long term bilateral contracts with their customers (as was done prior to the introduction of the STTM).

On-the-day balancing is a common feature of wholesale gas market designs due to the physical properties of natural gas. Unlike electricity, gas does not flow to its destination almost instantaneously. This requires users to provide producers and pipeline operators with forecasts of their demand the day before gas is required. On-the-day balancing is required to resolve the variations in ex ante schedules and actual flows on the gas day.

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648 ibid, p. 13.

Unlike the Victorian DWGM, there is no opportunity for STTM participants to adjust their positions during the gas day. In order to manage imbalances that occur at the hub between the ex ante market schedule and actual physical flows, AEMO operates the following mechanisms throughout the gas day:

- Market Operator Service (MOS);
- Market Schedule Variations (MSVs); and
- Contingency gas.

Each of these mechanisms are discussed below, along with an overview of how the ex ante commodity market and on-the-day balancing mechanism are financially settled.

Market Operator Service

MOS balances the difference between the scheduled pipeline flows and what is actually delivered or consumed at the hub, and is the primary on-the-day balancing mechanism. It is essentially a pipeline capacity service where shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand, or supply additional gas if flows to the hub are below demand. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges, which are discussed in section E.2.4 below.

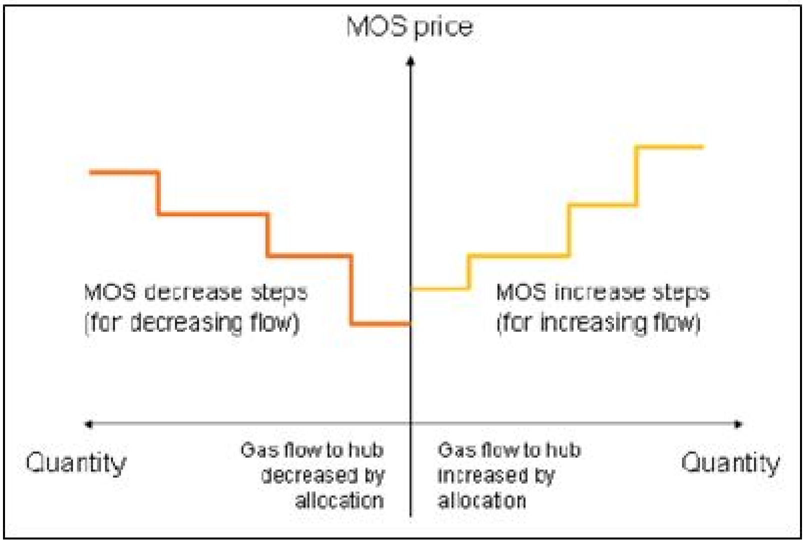
MOS is currently procured each month by AEMO from shippers with contracts on STTM-connected transmission pipelines. Shippers provide MOS increase offers for increased flows to the hub and MOS decrease offers for decreased flows to the hub, which are comprised of price-quantity steps.

On a gas day where deviations from the ex ante schedules occur, MOS is allocated to shippers by pipeline operators in accordance with MOS stacks provided for each pipeline by AEMO. If demand at an STTM hub is higher than expected, and as a result pipeline pressures decrease below operational levels, the pipeline operator flows additional gas from linepack in accordance with the increase MOS stack. Similarly, if hub demand is less than expected, the pipeline operator decreases the flow of gas to the hub by storing gas in the pipeline in accordance with the decrease MOS stack.

After the gas day, the pipeline operators notify AEMO of all MOS allocations for settlement purposes. This information also feeds into setting the ex post imbalance price, which is discussed further in section E.2.4.

Figure E.4 shows a MOS decrease stack on the left, where price increases as more gas is required to be stored in linepack, and a MOS increase curve on the right, where price increases for the more gas that is required to be supplied into the hub from linepack. A MOS cost cap of $40/GJ is the maximum amount that AEMO will pay for MOS. This is designed to protect the market from having to fund high costs for MOS where there is a lack of competition in the provision of MOS.

Figure E.4 MOS increase and decrease price stacks



Source: AEMO.

The price offered by a shipper to provide MOS reflects the cost of the pipeline park-and-loan service, and associated haulage charged by the pipeline operator, but not the cost of replacing the gas supplied.[649] When the market is short and MOS gas is required, the shipper is paid according to their MOS step price on a pay-as-bid basis. There is no cost to the market in accepting a MOS offer until MOS gas is actually allocated on a gas day.[650]

AEMO pays the MOS provider for the additional gas, or charges it for taking gas from the hub, at the ex ante market price two days after the gas day. This D + 2 ex ante price is used to price the cost of replacing MOS inventory as it allows the MOS provider to protect itself from price risks. An example of how this mechanism works is set out in Box E.1.

Box E.1 Replacing MOS gas supplied to the STTM

If a MOS provider supplies MOS on gas day 'D' due to a shortage at the STTM hub, AEMO will pay the MOS provider at the ex ante price two days later, or D+2, for that gas.

Paying the shipper at the D+2 price allows the shipper to bid to purchase gas to resupply its MOS inventory at the same price that AEMO has paid it for supplying the MOS gas. As such, the MOS provider is able to replenish its gas inventory without the risk of receiving a lower price that than paid by AEMO for supplying MOS gas to the STTM.

649 ibid, p. 37.

650 ibid.

For instance:

- MOS provider supplies 5 TJ of MOS gas on gas day D.
- At D+2 AEMO pays the MOS provider $3/GJ for supplying MOS gas.
- On the same day the MOS provider has the opportunity to bid to purchase gas to resupply its MOS inventory at $3/GJ.

In the Sydney STTM, MOS is provided on the Moomba to Sydney Pipeline and the Eastern Gas Pipeline. In Adelaide, MOS is provided by SEAgas and the Moomba to Adelaide Pipeline. In Brisbane, MOS is provided on the Roma to Brisbane Pipeline.

At the Sydney and Adelaide hubs, one of the transmission pipelines supplying the hub operates as a pressure control pipeline and the other operates as a flow control pipeline.[651] Pressure control pipelines generally provide the bulk of MOS gas.[652]

Market schedule variations

During the gas day, users' gas requirements become clearer and shippers are generally able to submit renominations to pipeline operators to adjust the flow of gas to the hubs. AEMO is able to account for intraday nominations, and shippers avoid deviation payments and charges, if shippers submit a market schedule variation (MSV) to AEMO to account for the changes.

MSVs are bilateral agreements negotiated between participants outside of the STTM that allow the quantity of gas by which a shipper varies from the market schedule to be matched by a receiving shipper or user. The receiving participant must confirm acceptance of an MSV before the variation can be applied in the STTM settlement process.[653]

If the MSV results in a change in demand at the hub, the variation will attract a variation charge, which is designed to encourage more accurate day-ahead forecasting. Variation charges are calculated on a sliding scale on a quantity and percentage basis such that the larger the variation, the larger the charge. MSVs that do not change the net flow at the hub are not penalised.

The framework around variation payments and charges is designed to provide an incentive for shippers and users to forecast their expected volumes accurately, while acknowledging that some changes are inevitable under the day-ahead market design. Variation charges are lower than deviation penalties (see section E.2.4) to encourage shippers to re-nominate expected changes in gas required to the pipeline operator.

Box E.2 illustrates how MSVs can be used in the STTM by participants.

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651 Flow control pipelines provide gas at a constant flow rate throughout the day while pressure control pipelines deliver gas to meet changes in the pressure at the hub.

652 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p 14.

653 ibid, p. 47.

Box E.2 MSVs are used by participants to avoid penalties[654]

If, for example, a retailer has been scheduled to flow 10 TJ in the ex ante scheduling process and, as the gas day unfolds, it has become clear that 12 TJ will be required. During the gas day the retailer may be able to ask the pipeline operator to flow an additional 2 TJ of gas.

If the retailer fails to inform AEMO that it has scheduled a further 2 TJ, AEMO will assume that the retailer, who in this case is a shipper and user, has over-supplied the market by 2 TJ and over-consumed by 2 TJ. A deviation payment and charge will be subsequently applied.

To avoid the deviation payment and charge associated with not following the ex ante schedules, the retailer can submit an MSV instructing AEMO to modify its shipper schedule by 2 TJ and its user schedule by 2 TJ. As the net impact at the hub is zero, the modified market schedule ensure no deviations payments or charges are applied.

Contingency gas

Contingency gas is a mechanism for balancing supply and withdrawals at a hub when the ex ante market and on-the-day pipeline flow variations are unable to match supply and demand within or over a gas day. Contingency gas provides pipeline operators and distributors with a means of avoiding, or at least minimising, the need to involuntarily curtail shippers supplying the hub or users at the hub.

AEMO procures contingency gas, but its use is determined in consultation with transmission pipeline and distribution network operators. Shippers able to increase supply to a hub and users and shippers able to reduce consumption will offer contingency gas to meet under-supply situations. Shippers able to decrease supply and users and shippers able to increase consumption at a hub will bid contingency gas to meet over-supply situations.

Trading participants can submit bids and offers for contingency gas at any time up to 6:00pm. the day before gas day. Contingency gas bids and offers are priced between the minimum and maximum market price caps. AEMO determines a price for contingency gas after the gas day, when all contingency gas called is known.[655]

A high contingency gas price is paid to providers whose contingency gas increases supply and/or reduces withdrawals. This price is set at the contingency gas offer price of the most expensive contingency gas provider who is called.

654 Ibid.

655 Ibid, p. 41.

A low contingency gas price is paid by contingency gas providers whose contingency gas decreases supply or increases consumption. This price is set at the contingency gas bid price of the least expensive contingency gas provider called.[656]

Contingency gas has not yet been required at any of the STTM hubs to date.

E.2.4 After the gas day

After the gas day the following aspects of the market are required to be determined for settlement to take place:

- actual gas flows;
- ex-post imbalance price;
- deviation payments and charges; and
- market settlement shortfall and surplus.

Determining actual gas flows

After the gas day, transmission pipeline operators for each STTM facility measure actual pipeline flows and allocate these quantities to each shipper on that pipeline. Where the pipeline allocations at a hub deviate from the ex ante schedule, the pipeline operator allocates these deviations to MOS providers in accordance with the MOS stacks provided by AEMO.

Distribution meter data is collected over a range of time frames and requires that non-interval meter customers are profiled. The quality of meter data available improves over time, so the meter data provided for the first settlement run is generally inferior to that of subsequent settlement runs produced over a period of months. These are functions that AEMO carries out in its capacity as retail market operator and are not part of the STTM.[657]

Settlement occurs monthly, but is recalculated after nine months due to the time it takes for meter data to be finalised. The STTM provides for further revisions for a period of 18 months if there is material impact on participants due to mistakes in the process or if faulty meters are discovered.[658]

Ex post imbalance price[659]

The ex post imbalance price is calculated after the gas day to determine a price that reflects the changes that actual flows to the hub would have had on the ex ante market. It is determined using the same data as the ex ante market schedules, but includes a

656 ibid, p. 43.

657 ibid, p. 46.

658 ibid, p. 53.

659 ibid, p. 49-50.

dummy bid or offer that simulates the effect of the deviations, such as through MOS, if they had been scheduled in the ex ante market.

If more gas was scheduled than consumed on the gas day, the market supply curve is moved right by the quantity by which the market is long. If more gas was consumed than scheduled, the market demand curve is moved right by the quantity by which the market is short.

The ex post imbalance price is published after the gas day and can be used in settlement to calculate deviation payments and charges.

Deviation payments and charges[660]

Deviations are the difference between the quantity of gas that the STTM is expecting to flow—as modified by MSVs, MOS and contingency gas—and the actual quantity of gas that flowed. As discussed above, actual quantities of gas that flow to and from the hub will not exactly match the ex ante market schedule for any given gas day.

Where a shipper has supplied more gas than was required in the market schedule, or a user consumed less gas than was expected in the market schedule, it will receive a deviation payment from AEMO. The deviation payment is calculated by multiplying the deviation quantity by the minimum of the ex ante price, ex post price, the decrease MOS price (if any) and the low contingency gas price (if any).

Where a shipper or a user is "short" at the hub, it must pay a deviation charge to AEMO. Deviation payments and charges are used to offset the cost of MOS gas. The deviation charge is calculated by multiplying the deviation quantity by the maximum of the ex ante price, ex post price, the increase MOS price (if any) and the high contingency gas price (if any).

Deviation payments and charges reflect the impact the deviation had on the STTM and will vary for each participant. However, because deviations and MOS are calculated on a different basis, there is usually a shortfall or surplus, which is dealt with through the settlement process described below.

Market settlement shortfall and surplus[661]

Settlement occurs monthly and is net of all ex ante sales and purchases, deviations charges, variation charges, capacity charges, settlement revisions and any payments for MOS and contingency gas. The settlement payments to trading participants do not usually match the settlement charges paid by trading participants, with the various components above all contributing to the market being in surplus or shortfall.

For each month, the market must end up in balance with respect to trading income and outgoings. If there is a shortfall, any deviating parties are charged their share of the

660 ibid, p. 49.

661 ibid, p. 53-57.

shortfall, pro-rated based on the absolute value of their deviations over the course of the month.

If there is a surplus, then the excess money is returned to the deviating parties based upon their share of monthly deviations up to a cap of 0.14 $/GJ, with the residual amount being returned pro-rata based on withdrawals over the course of the month.

E.3 STTM rule changes

The following table sets out the STTM rule changes considered by the AEMC since market start.

Table E.2 STTM rule changes

Determination date	Proponent	Rule change	Brief Description
7 May 2015	AEMO	Contingency Gas Evidentiary Changes	Improve incentives for trading participants to efficiently supply and price contingency gas in the STTM.
3 April 2014	AEMO	STTM settlement surplus and shortfall	Provides guidance to AEMO to develop STTM Procedures for the allocation of any settlement surplus or shortfall to STTM participants.
20 June 2013	AEMO	STTM deviations and the settlement surplus and shortfall	Reduce the financial risks of market participation and improve price signals and certainty regarding the costs to trading participants of deviating from their daily schedules.
23 May 2013	AEMO	Market operator service - timing and eligibility	Facilitate greater competition in the provision of MOS in the STTM.
28 February 2013	AEMO	STTM Brisbane participant compensation fund	Increase the size of the STTM Brisbane compensation fund as the existing arrangements did not reflect the size of the Brisbane market.

Determination date	Proponent	Rule change	Brief Description
28 August 2012	AEMO	STTM Market Schedule Variation Transactions	Enables users in the STTM to submit MSVs to AEMO.
13 October 2011	AEMO	Short Term Trading Market - Market Schedule Variation	Removal of the timing provision for the submission of MSV transactions from the NGR.
15 September 2011	AEMO	Brisbane Hub	Implement the Brisbane STTM.
5 May 2011	AEMO	STTM Data Validation and Price Setting Process	Provide the market operator with more time to review and confirm the accuracy of STTM information.
17 March 2011	AEMO	Calculation of STTM Participant Compensation Fund Contributions	Clarify the process of calculating the STTM Participant Compensation Fund.
9 December 2010	AEMO	Timetable for Prescribed Gas STTM Reviews	Consolidate the first three prescribed STTM reviews to be completed by 31 March 2012.
4 November 2010	AEMO	Calculation of interest rate for gas markets	Provides for the calculation of interest in the NGR to use a simple interest methodology.

E.4 STTM participants

The following tables list the registered participants in each of the STTM hubs.

Table E.3 Adelaide STTM

Adelaide STTM	
Shippers AGL, Adelaide Brighton Cement, Alinta, EnergyAustralia, Lumo, OneSteel, Origin, Pelican Point Power, Santos, Simply Energy, South Australian Water Corporation	**Users** AGL, Adelaide Brighton Cement, Alinta, EnergyAustralia, Lumo, Origin, Simply Energy, South Australian Water Corporation
Pipeline owners Australian Gas Networks (Envestra), Epic Energy, SEA Gas	**Other** Logica GRMS

Table E.4 Brisbane STTM

Brisbane STTM	
Shippers AGL, Alinta, BP Australia, ERM Business Energy, Incitec Pivot, Origin, Santos, Stanwell	**Users** AGL, Alinta, BP Australia, Incitec Pivot, Origin, Stanwell, Visy Paper
Pipeline owners APT Petroleum Pipelines (RBP - APA Group), Allgas Energy, Australian Gas Networks (Envestra)	**Other** AEMO (allocation agent)

Table E.5 Sydney STTM

Sydney STTM	
Shippers AGL, BHP Billiton Petroleum, BlueScope Steel, Covau, EnergyAustralia, Esso Australia, Lumo, OneSteel, Origin Energy, Qenos, Santos	**Users** AGL, BlueScope, Covau, EnergyAustralia, GOEnergy, Lumo, M2Energy (T/As Dodo Power & Gas), OneSteel, Origin, Qenos, Red Energy, Santos, Snowy Hydro, Visy Paper
Pipeline owners East Australian Pipeline (MSP - APA Group), Jemena Eastern Gas Pipeline, Jemena Gas Networks	**Other** Logica GRMBS

Source: AEMO data.

F Operation of the Declared Wholesale Gas Market

This appendix provides a detailed overview of the DWGM design and operation. It sets out the:

- history and policy objectives of the DWGM;
- design and structure of the DWGM;
- rule changes carried out by the AEMC to date; and
- current market participants in the DWGM.

F.1 History and policy objectives of the DWGM

Market-start

The DWGM was established by the Victorian Government in March 1999 and as part of this process, the following occurred:[662]

- the ownership and operational functions of the pipeline transmission system were separated and a decision was made to operate the DTS on a market carriage basis;
- the DWGM was developed to enable participants to trade imbalances; and
- an independent system operator, VENCorp (later AEMO), was given responsibility for operating both the DWGM and the DTS, balancing gas supply and demand and transportation capacity through a centrally co-ordinated scheduling process.[663]

The rationale for adopting the market carriage model[664]and the DWGM in Victoria can be summarised as follows:[665]

1. It reflects the physical characteristics exhibited by the DTS:
    - The DTS is highly a meshed network.

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662 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 53.

663 VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 22.

664 Under a market carriage framework, capacity on a pipeline system is available to all users. A shipper does not have rights in relation to being able to use capacity nor would it face penalties for exceeding a certain capacity. Market carriage in Victoria (and its difference to contract carriage elsewhere) is covered in detail in Chapter 4.

665 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 11; and VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, pp. 21-24.

- The amount of gas that can be stored in the DTS is also quite small and cannot be relied upon to manage significant deviations between demand and contracted supply.[666]

- The physical characteristics of the DTS, coupled with the fact that the demand for gas in Victoria exhibits a significant degree of seasonal and daily variability (high residential heating load), mean that the DTS must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained.

- The physical characteristics exhibited by the DTS also mean that it can be very difficult to determine how to define firm capacity rights to shippers.[667]

2. It was expected to support full retail contestability – the market carriage model and the DWGM were seen as a way of encouraging new entry by retailers because they would not need to enter into long term gas transportation agreements and they would have equivalent access as incumbent shippers to a mechanism to trade imbalances and purchase gas at the spot price.

3. It was designed to encourage diversity and security of supply and upstream competition – the transparency of pricing provided by the DWGM and the operation of the market carriage model were expected to encourage the development of new sources of supply and upstream competition.

Move to ex ante intra-day trading

Between 1999 and 2007, the DWGM market price was determined on a daily ex-post basis. However, on 1 February 2007, the market moved to ex ante intra-day trading following a review in 2003-04 by VENCorp. The 2003–04 review, also known as the Pricing and Balancing Review (PBR), aimed to:[668]

- provide more efficient and transparent pricing signals;
- improve market interaction and response to pricing signals;
- provide adequate incentives and flexibility for demand-side response; and
- facilitate investment in pipeline infrastructure.

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666 A 2002 report by VENCorp states that total linepack in the DTS varies between about 450 TJ and 600 TJ over each day as the system demand is satisfied and that on peak days over 1,100 TJ is shipped through the network, or approximately twice the entire linepack in the system. By way of comparison, the then peak demand on the Moomba pipeline was stated to be approximately 25 per cent of the daily transported volume. See: VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 23.

667 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 11.

668 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, July 2013, pp. 11-12.

VENCorp recommended a three stage approach to reforming the DWGM, namely:[669]

1. stage 1 – introduction of ex ante intra-day pricing;

2. stage 2 - introduction of transmission rights; and

3. stage 3 - development of a number of hubs and introduction of capacity rights.

To date, the only changes that have been made to the DWGM are those that were recommended to occur in stage 1. VENCorp found that the existing ex post design did not provide participants with either the ability or the incentive (ie, the price signal) to respond to changing market conditions during the day, which was a driver behind switching to a system of ex ante pricing in 2007.[670]

Authorised Maximum Daily Quantity

Shippers utilising the DTS cannot reserve firm capacity (unlike contract carriage pipelines). They may, however, have an Authorised Maximum Daily Quantity (AMDQ) allocation or an AMDQ credit certificate (AMDQ cc).[671] This section presents the history of AMDQ and AMDQ cc. A detailed discussion of the benefits to holders of these two products is provided in section F.2.2 below.

AMDQ was first allocated at market start and was (and has remained) commensurate with the capacity of the Longford-Melbourne pipeline at that time when it was the primary sole source of gas supply for the DWGM. The rights to the existing 990TJ of capacity were allocated to customers in two tranches (recognising that the DTS was comprised of pre-existing assets that had at least partially been paid for by existing customers of the Victorian Gas and Fuel Corporation):

1. large industrial and commercial (Tariff D) sites were allocated AMDQ to match their maximum daily quantity under contracts with the Victorian Gas and Fuel Corporation at the time; and

2. the balance of 990 TJ, after Tariff D allocations, was allocated as Tariff V block AMDQ to all small commercial and residential customers.[672]

The rationale for allocating the original AMDQ to customers rather than market participants, retailers or shippers was to not create a barrier to retail competition.[673]

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669 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 55.

670 VENCorp, *Victorian Gas Market Pricing and Balancing Review – Recommendations to Government*, 30 June 2004.

671 Unless otherwise stated, the information in this sub-section references: AEMC, *National Gas Amendment (Portfolio Rights Trading) Rule 2014*, Final Rule Determination, 27 November 2014.

672 Market participants supplying Tariff V customers were allocated a share of the Tariff V block AMDQ proportionately to their portfolio Tariff V demand on system peak demand days.

673 For example, if AMDQ were held by retailers, there was a concern that those retailers who won customers from rival retail businesses would then be forced into a position of either trying to negotiate with that rival retailer to sell them AMDQ, or take on additional risk.

The DTS has expanded and extended since 2008 and the new pipeline capacity has been allocated as AMDQ credit certificates (AMDQ cc).[674]

As new pipeline capacity has become available, AMDQ cc have been created to provide similar benefits to those arising from AMDQ on the Longford pipeline.[675] The increase in pipeline capacity resulting from an extension or expansion project is agreed between APA (as the DTS owner) and AEMO (the operator of the DTS and the DWGM). Once agreement is reached and the new capacity becomes operational, new certificates are created.

AEMO allocates the AMDQ cc to market participants for quantities and periods as directed by APA (which reflect the outcome of a competitive tender process APA manages). In this process, interested market participants are able to tender for an amount of AMDQ cc for a specified period.[676]

The figure below illustrates the expansion of the DTS since 1998, which has resulted in a total of 508 TJ of AMDQ cc made available for injections into the DWGM.

Figure F.1 Allocation of AMDQ and AMDQ cc as at 2014

Source: AEMC, *National Gas Amendment (Portfolio Rights Trading) Rule 2014*, Final Rule Determination, 27 November 2014, p. 32.

AMDQ cc is not differentiated by final customer (Tariff V or D) and is not allocated directly to customers. Rather, market participants with AMDQ cc must advise AEMO whether the allocated AMDQ cc are to be nominated to either:

674 Maximum system capacity of the DTS is currently approximately 1,350 TJ per day. See: AEMO website, available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-DTS-Capacity

675 Since the commencement of the DWGM, the capacity of the DTS has increased as a result of numerous augmentations, including the Interconnect, the South West Pipeline, the connection of the former Western Transmission System, the Brooklyn Lara Loop and the BassGas project.

676 However, the AEMC note there are no requirements for this process to occur.

- specific customer sites; or
- the nominal reference hub.[677]

Rule changes

Section 295(3) of the NGL currently provides that applications for rule changes relating to the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[678]Since commencement of the DWGM in 1999, AEMO has submitted six rule changes to the AEMC for consideration since it assumed responsibility for rule changes from VENCorp in 2009. These are summarised in Table F.1.

F.2 Design and structure of the DWGM

It is compulsory for market participants in Victoria to trade through the DWGM. In particular, any retailers, large customers or gas traders that want to either supply gas into Victoria, or export gas via the DTS, must use the DWGM. A range of participants, such as retailers, gas-fired generators and large industrial customers, currently use the DWGM. Participants all use the market to physically sell or procure gas. Table F.2 sets out the number and type of participants currently registered in the DWGM.

An important feature of the arrangements in Victoria is an independent market and system operator (AEMO) that operates the pipeline separately from the pipeline owner. It manages the receipt, transport and delivery of gas as part of the gas market. APA makes the Victorian DTS available to AEMO under a Service Envelope Agreement (SEA) and makes available a single reference service comprising a Tariff Transmission Service.[679]

The key features of the current DWGM market are as follows:

- the market sets the ex ante prices for gas trades at a publicly available price at the beginning of each scheduling period, enabling participants to respond to prices;
- the market is a net market allowing settlement on the difference between a market participant's injections and withdrawals (imbalance);
- market participants submit injection and/or withdrawal bids and their own demand forecasts; AEMO uses these to produce the overall system forecasts;
- there are five scheduling times (6.00am, 10.00am, 2.00pm, 6.00pm and 10.00pm) where schedules covering the remainder of the gas day can change;

677 The reference hub is a notional site within the DTS established for the purpose of valuing AMDQ and AMDQ cc. When a market participant does not nominate its entire AMDQ to actual sites, it has to nominate its residual AMDQ somewhere

678 Victoria is currently the only adoptive jurisdiction.

679 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 11.

- settlement payments are determined for each scheduling time based on traded quantities and prices; and
- mechanism of ancillary payments and uplift cost allocations are used to manage the cost and impact of transmission constraints.

A more detailed overview of the key design features of the DWGM and how they work in practice are provided below.[680]

F.2.1 DWGM overlay with market carriage pipeline framework

To ship gas through the DTS, shippers must register with AEMO as a participant in the DWGM. In doing so, shippers must enter into a Transmission Payment Deed with APA, which states that shippers agree to pay regulated transmission tariffs directly to APA as owner of the DTS. Tariffs for use of the DTS are known as Transmission Use of System (TUoS) charges and reflect the cost to deliver gas from the seven injection points to the 27 withdrawal zones and points on the DTS.[681]

Shippers proposing to withdraw gas from the market must also enter into a connection agreement with either a gas distribution company or APA, or have arrangements to transport the gas to a connected transmission pipeline.

F.2.2 Authorised Maximum Daily Quantity

Collectively, AMDQ and AMDQ cc are commonly known as 'AMDQ'.[682] Broadly, there are two different types of right (or benefits) that are created by holding AMDQ, namely:

1. Financial rights: Market participants can use part or all of their AMDQ to hedge against congestion uplift charges.[683]
2. Physical access rights:
    (a) Curtailment 'protection' rights - unauthorised customers, where operationally practicable, will have their gas supply curtailed ahead of customer sites with AMDQ in the event of transmission constraints resulting in supply shortfalls.[684]

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680 Unless otherwise stated, the information in this sections below reference: AEMO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

681 APA group website, available at: http://www.apa.com.au/our-business/economic-regulation/vic/victorian-transmission-system.aspx

682 Unless otherwise stated, the information in this sub-section references: AEMC, National Gas Amendment (Portfolio Rights Trading) Rule 2014, Final Rule Determination, 27 November 2014.

683 We note that AMDQ only offer a limited hedge against congestion uplift and no hedge against surprise or common uplift. This is discussed further in section F.2.9.

684 In practice, we understand this is limited.

(b) Injection tie-breaking rights (also known as priority in scheduled injections) – when there are equally priced injection bids, participants with AMDQ are scheduled first.

(c) Withdrawal tie-breaking rights (also known as priority in scheduled withdrawals) – when there are equally priced controllable withdrawal bids, participants with AMDQ are scheduled first.

In 2014 the procedures pertaining to AMDQ were modified to incorporate a proposal by APA to enhance interoperability between the DTS market carriage system and adjacent contract carriage markets. Specifically, the procedures were modified so that AMDQ was only assigned to a system withdrawal point at an interconnected facility (eg at Culcairn) if a market participant was entitled to sufficient firm capacity on that interconnected facility to cover the quantity being assigned and any existing holdings (ie that the market participant holds sufficient firm haulage contracts for the AMDQ allocation to occur).[685]

AMDQ can be acquired in a number of ways, including by:

- entering into an agreement with existing holders of AMDQ to transfer an agreed quantity from one site to another or to the reference hub;
- entering into an agreement with existing holders of AMDQ cc to transfer an agreed quantity at the reference hub;
- applying and negotiating with the DTS service provider for AMDQ cc when they expand the capacity of the DTS or when existing AMDQ cc contracts that others hold expire;
- contracting with the DTS service provider to privately expand the DTS capacity; [686]and
- bidding for and purchasing spare AMDQ at auctions conducted by AEMO from time to time.

Historically, limited quantities of AMDQ have been traded between participants. In its 2011 paper outlining transmission capacity issues in the DWGM, AEMO noted it had auctioned 12.5 TJ of unallocated AMDQ from defunct Tariff D customer sites and has transferred a further 75 TJ in 106 transactions since transfers commenced in 2001. Of the transfers, 43 per cent by volume and 65 per cent by number were internal transfers to related organisations.[687]

685 See: AEMO, *AMDQ Procedure Proposal*, 28 February 2014; and AEMO, *Notice to Participants of AEMO's decision on making the Wholesale Market AMDQ Procedures (Victoria)*, 10 June 2014.

686 We understand that this has not happened yet to date.

687 AEMO, *Transmission Capacity Issues in the DWGM*, 21 June 2011, p. 6.

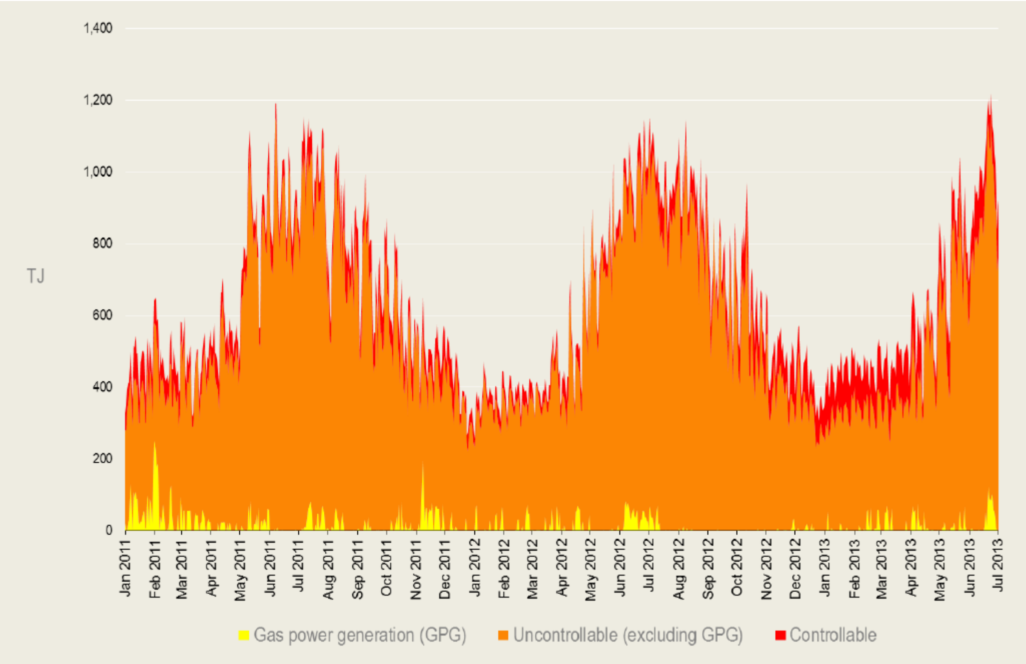
F.2.3 Bidding procedure

Before outlining the specific bidding procedures currently in the DWGM, it is first useful to outline the three concepts of supply and demand in the DWGM, ie:

1. Controllable withdrawals (demand):
   - Market participants can make offers to withdraw gas from the market with a defined gas quantity and price.
   - This type of withdrawal can respond to the wholesale price and follow schedules and so is termed 'controllable withdrawal'.
2. Uncontrollable withdrawals (demand):
   - Most of the gas demand in the DWGM varies with temperature, seasons, day of week, weather conditions, and various other external factors.
   - Generally, the highest gas loads occur during the winter. Typical examples of these types of withdrawals include gas demands from households (heaters, hot water), small and large business/industry, and Gas Fired Power (GFP) generators (many of them are 'peaking' plants as they can respond to change in NEM demand and prices, unlike coal-fired power plant).
   - Since these withdrawals do not easily respond to the wholesale price and are not capable of following schedules, they are termed 'uncontrollable withdrawals'.
3. Injections (supply):
   - Market participants need to have contracts with producers, storage providers, or interconnecting transmission systems to be able to inject.
   - Similar to controllable withdrawals, market participants can make offers to inject gas to the market with a defined gas quantity and price.
   - Injections are termed 'controllable', because they can respond to the wholesale price and follow schedules.

The figure below shows total withdrawals from the DWGM over the period 2011 - 2013, showing that in Victoria the vast majority of demand comes from uncontrollable sources such as households (heaters, hot water etc) as well as small and large business/ industry.

Figure F.2 Uncontrollable demand makes up the majority of DWGM demand, daily data 2011 - 2013



Source: AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, July 2013, p. 15.

Market participants who intend to inject gas or withdraw gas as controllable withdrawals must submit bids to do so.

Market participants can specify up to ten steps of prices and daily quantities in each bid for each injection and controllable withdrawal point:

- for injection bids, bid steps are provided in increasing price order with increasing cumulative quantities; and
- for controllable withdrawal bids, bid steps are provided in decreasing price order with increasing cumulative quantities.

Bid prices can vary between $0/GJ and the market price cap (Value of Lost Load (VOLL)) which is currently set at $800/GJ.

Market participants may revise price and quantity bids at least nine times per day (the scheduling/re-scheduling process is outlined in more detail in section F.2.4 below). However, the revised total bid quantities must not be less than that already scheduled in any previous schedules on that gas day. All bid quantities, including rebids, are for the 24 hour gas day.

F.2.4 Gas scheduling

Gas scheduling is a process that AEMO conducts a number of times each gas day to provide hourly injection schedules for each market participant, and schedules for any controllable withdrawals, using market participants' submitted bids and demand forecast[688] as the primary inputs.[689]

Specifically, AEMO uses this information to produce and publish pricing and operating schedules at each scheduling time. Namely:

- Operating schedules:
  - Determines individual market participant's scheduled hourly injections and withdrawals at each injection/withdrawal point.
  - Takes into account physical pipeline constraints, linepack distribution, system limits on pressure and gas flows and demand and supply applicable to each node.
  - The market clearing algorithm used in optimising each operating schedule minimises the cost of supplying the forecast gas demand within the pipeline system security limits.
  - Quantities from operating schedules direct the operation of the gas system and injections into the system over the gas day.
- Pricing schedules:
  - Determines the ex ante market prices based on the bids and demand forecasts (ie, using a 'bid stack') for all locations on the network. This process is outlined in more detail in section F.2.5 below.

On any given gas day, AEMO prepares and issues at least nine pricing and operating schedules, ie:

- five standard schedules for the current gas day at four-hour intervals at 6.00am, 10.00am, 2.00pm, 6.00pm, and 10.00pm;
- three gas schedules for the next gas day at 8.00am, 4.00pm and 12.00am;
- one two-days-ahead schedule for gas day after the next day at 12.00pm; and
- ad-hoc schedule(s) between standard schedules on the current gas day, but only if there are impending or imminent threats to system security requiring urgent action.[690]

The 6.00am schedule, also known as the beginning-of-day (BoD) schedule, covers the 24 hours from 6.00am. Information used and issued in the BoD schedule is updated in

688 Market participants who supply uncontrollable withdrawals must submit hourly site- and non–site-specific demand forecasts to AEMO.

689 We note that the form that market participants enter market bids in is by schedule, while demand forecasts are entered by hour.

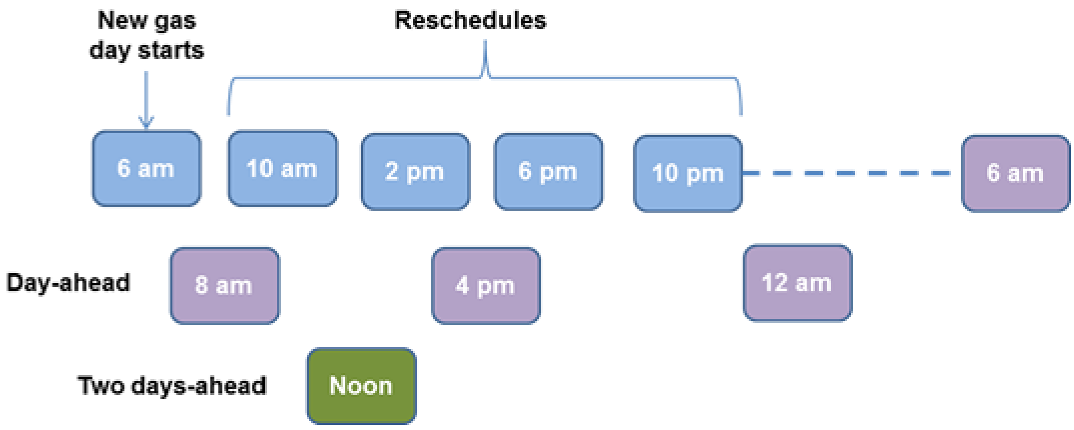
690 Ad hoc schedules do not alter the Market Price. They change operating schedule quantities only.

subsequent re-schedules and the 10.00am, 2.00pm, 6.00pm and 10.00pm re-schedules provide for any changes for the remaining 20, 16, 12 and 8 hours of the current gas day, respectively.

The period between scheduling times is called the scheduling interval, and the period of time from any point in a day to end of gas day is called the scheduling horizon. The scheduled quantities are for the whole gas day (hour by hour) but only the part in the scheduling horizon can be changed.

The preparation of schedules by AEMO in any given day (and the timing of these schedules) is shown in the figure below.

Figure F.3 The daily preparation of schedules by AEMO



Source: AEMC based on AEMO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

Market participants need to submit the required scheduling input data at least one hour prior to the schedule start time for all standard schedules.[691] This allows AEMO time to compile and assess the input data, run the algorithms, and confirm that the outputs are satisfactory before issuing the schedules.

After the scheduling process, each market participant receives the key output of the operating schedule – an individual Market Information Bulletin Board report detailing what quantity of gas and where they are committed to inject or withdraw for each hour of the gas day.

F.2.5 Determination of the ex ante market price

The key output in a pricing schedule is the ex ante market price. This market price is determined as follows:

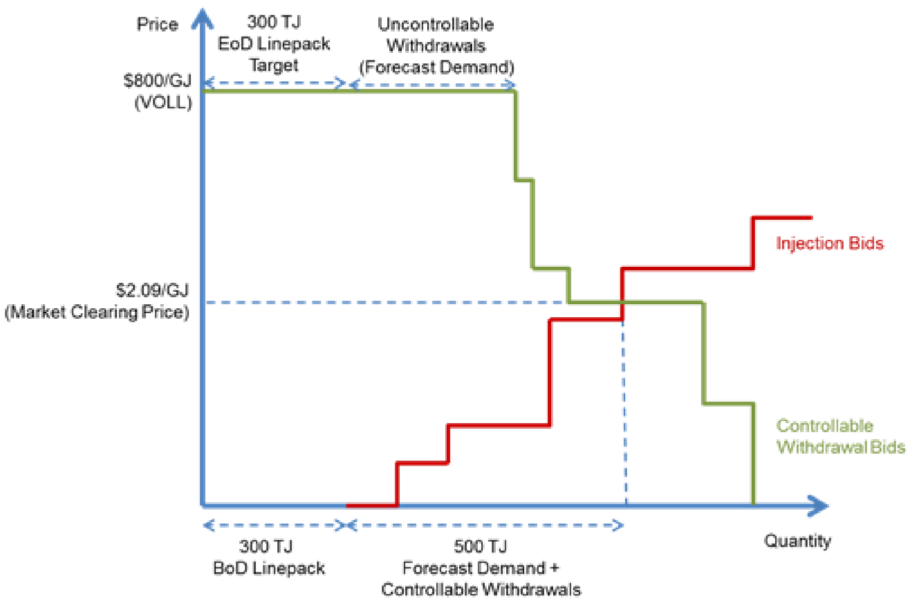
- gas withdrawals (forecast demand plus controllable withdrawals) are met by the cheapest gas bids into the system, ie through a 'bid stack' process; and

691 The exception is the last one-day ahead schedule where the data must be submitted by 10.00pm.

- the market price is determined by the marginal price of the cumulative injection bid quantities that are required to meet the aggregate of all market participants' demand forecasts and controllable withdrawal bids.

The following figure illustrates how the ex ante market price for a given schedule is determined in practice.

Figure F.4 Ex ante market price determination in the DWGM



Source: AEMC analysis.

In determining the pricing schedule, rule 221(3)(f) of the NGR requires AEMO to apply demand or supply point constraints to reflect limitations on pipelines or facilities that are external to the DTS. This is intended to ensure that external factors do not distort the market price.

However, in determining external demand or supply point constraints, rule 221(4) prohibits AEMO from taking into account operating conditions within the DTS. This is intended to ensure that any constraints on the DTS do not find their way into the pricing schedule. In this way, the pricing schedule remains 'unconstrained'.[692]

692 In 2014, AEMO noticed that in practice, the pricing schedule does take into account operating conditions within the DTS when determining some supply or demand point constraints. The implications of the AEMO practice is that, in instances where injections to, or withdrawals from, the DTS are constrained, constraints are applied in both the pricing and operational schedules. We understand that this has the following effects: (1) The market price is increased (for constrained injections) or decreased (for constrained withdrawals) compared to an unconstrained pricing schedule; (2) The congestion pricing signals that would otherwise be provided through uplift payments are suppressed, potentially devaluing the benefits of AMDQ and AMDQ credits; and (3) Bids that are physically infeasible due to external constraints do not impact the market (this is in accordance with market design). We understand that AEMO proposes to implement a new operating practice whereby AEMO will apply all DTS constraints to the operating schedule only.

An administered price period may occur if the market has been suspended, a market price or pricing schedule is unable to be published by the required time or the cumulative price threshold has been reached. During this period the market price is capped at $40/GJ.

The cumulative price threshold is $1,800/GJ and is calculated as the marginal clearing price over the previous 34 scheduling intervals and the current scheduling interval.

F.2.6 Imbalance payments

Imbalance payments are payments for the net difference between scheduled injections and withdrawals of gas by a market participant. Imbalance payments are determined on an ex ante basis.

In general, market participants endeavour to align their intended daily gas injections and withdrawals to avoid exposure to the spot market, unless the market participants are either sole injectors or withdrawers. However, intended daily gas injections and withdrawals may differ for a given day and market participants must pay the costs for the imbalance quantities in the form of daily imbalance payments, which can be positive or negative.

The imbalance payment for each market participant is calculated based on the imbalance quantities between their 6.00am scheduled daily injections and withdrawals at the 6.00am market price, plus the subsequent imbalance payment based on changes in the imbalance quantities at each reschedule priced at the reschedule price.

In summary, if a market participant:

- withdraws and injects the same quantity of gas over the course of the day the imbalance payment will be 0;
- withdraws more gas than it injects over the course of the day the imbalance payment will be positive (this implies that the given market participant has purchased gas from the gas market and must pay for the over-withdrawal to AEMO); and
- withdraws less gas than it injects over the course of the day the imbalance payment will be negative (this implies that the given market participant has sold gas to the gas market and is entitled to receive a payment from AEMO for the quantity of gas sold).

The boxes below outline how imbalance payments operate in practice.

This approach is compliant with the NGR and does not require a rule change. Further, we understand that AEMO intends to have the issue settled before winter 2015.

Box F.1 Imbalance payments in the DWGM

Suppose a market participant has scheduled injection and scheduled withdrawal at the BoD schedule of 70 GJ and 40 GJ, respectively. Suppose also that as the day progresses, this market participant changes its injections and withdrawals at each reschedule as follows:

- 10am – scheduled injections remain at 70 GJ but scheduled withdrawals rise to 45 GJ;
- 2pm – scheduled injections remain at 70 GJ but scheduled withdrawals fall to 35 GJ;
- 6pm – scheduled injections fall to 50 GJ and scheduled withdrawals remain at 35 GJ; and
- 10pm – scheduled injections and withdrawals remain at 50 GJ and 35 GJ, respectively.

The calculation of the imbalances (in GJ), the change in imbalance (in GJ) and the associated imbalance payment is shown in the table below.

Schedule	Scheduled Injection (GJ)	Scheduled Withdrawal (GJ)	Market Price ($/GJ)	Imbalance (GJ)	Change in Imbalance (GJ)	Imbalance Payment ($)	Who Pays?
6:00 AM	70	40	$5.00	-30	NA	-$150	AEMO
10:00 AM	70	45	$6.00	-25	5	$30	MP
2:00 PM	70	35	$4.00	-35	-10	-$40	AEMO
6:00 PM	50	35	$4.00	-15	20	$80	MP
10:00 PM	50	35	$5.00	-15	0	$0	NA
Total Daily	-	-	-	-	15	-$80	AEMO

Source: AEMC analysis (based on AEMO training material).[693]

F.2.7 Deviation payments

Deviation payments are used to settle differences between market participants' scheduled and actual behaviour (ie market participants' actions compared to intentions). In contrast to imbalance payments therefore, deviation payments are calculated on an ex-post basis.

Market participants' deviations from their demand forecasts and scheduled quantities (injections and withdrawals) in a given schedule will have physical and financial impacts on the outcomes of the next schedule. For example, if a market participant

693 AMEO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

under-forecasts their demand (or under-schedules injections) in the 6.00am schedule this will cause a decrease in linepack requiring more gas to be injected at the 10.00am schedule, and potentially an increase in gas market price. Likewise, deviations in the 10.00am scheduled quantities and demand forecasts will affect the 2.00pm market outcomes.

Deviation payments also provide market participants with a tool to trade linepack between schedules by managing their net positions in supply and demand.

The deviation quantity is calculated as the difference between the following for each market participant:

- actual withdrawals less scheduled withdrawals; and
- actual injections less scheduled injections.

Deviations are valued at the next scheduled price because they can influence that price (eg a deviation in 10.00am – 2.00pm interval is settled at the 2.00pm reschedule market price). Deviations in the last reschedule of the day are settled at the following 6.00am price.

The table below outlines how deviation payments operate in practice, as well as the party responsible for paying the deviation payment.

Schedule	Scheduled Injection (GJ)	Actual Injection (GJ)	Injection Deviation (GJ)	Scheduled Withdrawal (GJ)	Actual Withd rawal (GJ)	Withdrawal Deviation	Net Deviation (GJ)	Next scheduled market price ($/GJ)	Net deviation payment ($)	Who Pays ?
6:00 AM	30	28	-2	30	25	-5	-3	$5.00	-$15.00	AEMO
10:00 AM	35	36	1	30	30	0	-1	$6.00	-$6.00	AEMO
2:00 PM	35	50	15	30	31	1	-14	$4.00	-$56.00	AEMO
6:00 PM	20	22	2	25	18	-7	-9	$4.00	-$36.00	AEMO
10:00 PM	20	18	-2	15	16	1	3	$5.00	$15.00	MP
Total Daily	140	154	14	130	120	-10	-24		-$98.00	AEMO

Source: AEMC analysis (based on AEMO training material).[694]

F.2.8 Ancillary payments

It is not always possible to schedule the cheapest gas to meet the required demand for a given gas day. When the system is congested, gas that is more expensive than the market price may be scheduled. Ancillary payments are compensatory payments to market participants who are affected by these events.

An example of when an ancillary payment would apply is on a high demand day in Melbourne. The gas used by customers during the gas day's peak period (evening)

694 AMEO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

may exceed the amount of gas that can flow on the main pipelines into Melbourne. In this case, LNG from the Dandenong LNG storage facility could be scheduled to be injected into the system to avoid breaching pressure limits on the pipeline, even if its price is well above the market price for that scheduling interval. Market participants supplying this LNG to the market would be paid the price they bid, rather than the lower market price.[695] The amount paid to these suppliers that is the difference between the bid price and the market price is known as an ancillary payment.

The box below outlines how ancillary payments operate in practice.

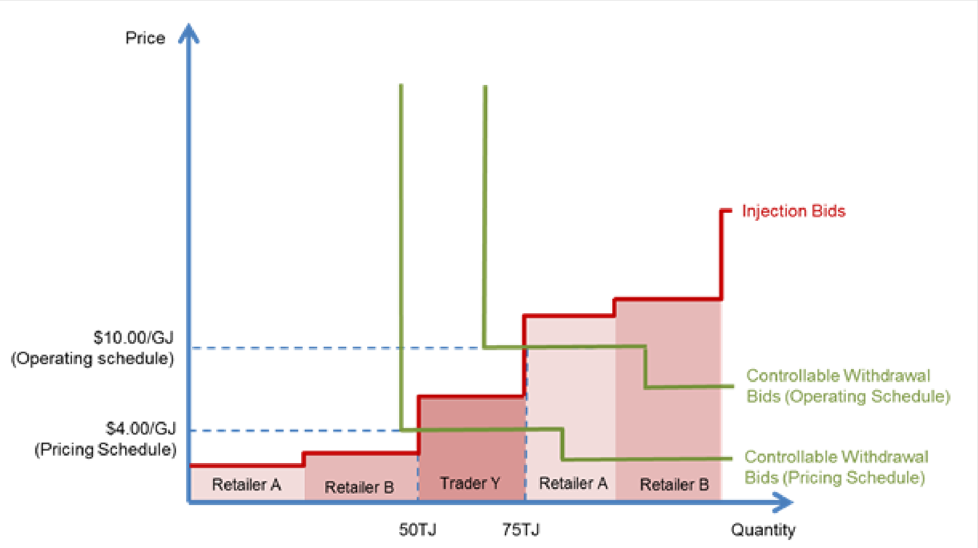
Box F.2 Ancillary payments in the DWGM

Suppose that AEMO has to call on an offer by a particular market participant ('Trader Y') to inject 25 TJ of gas at $10/GJ in order to resolve a localised pressure constraint for a one hour period. At the same time, the market price is $4/GJ.

Trader Y will continue to receive the market price of $4/GJ for the 25TJ they inject. However, they will be paid an ancillary payment for injecting the called upon 25 TJ at a price determined by the difference in the participant's offered price and the market price for that period, ie $6/GJ (10-4). Trader Y will therefore receive the following:

- an injection imbalance payment of $100,000 (ie 25,000 GJ x $4/GJ); and
- an ancillary payment of $150,000 (ie 25,000 GJ x $6/GJ).

This is illustrated via the simplified depiction of the difference between the pricing and operating schedule below.



Source: AEMC analysis.

695 In other cases (albeit less likely), market participants may be scheduled to withdraw gas that is more expensive than their bid prices. This section will focus on injection ancillary payments.

F.2.9 Uplift payments

Uplift payments are paid by market participants to fund ancillary payments, ie, when payments are made to market participants who provide gas to (or withdraw gas from) the market at above the market price. To the extent possible, uplift is charged to market participants whose actions cause the ancillary payments.

There are four categories of uplift payments:

1. congestion uplift;

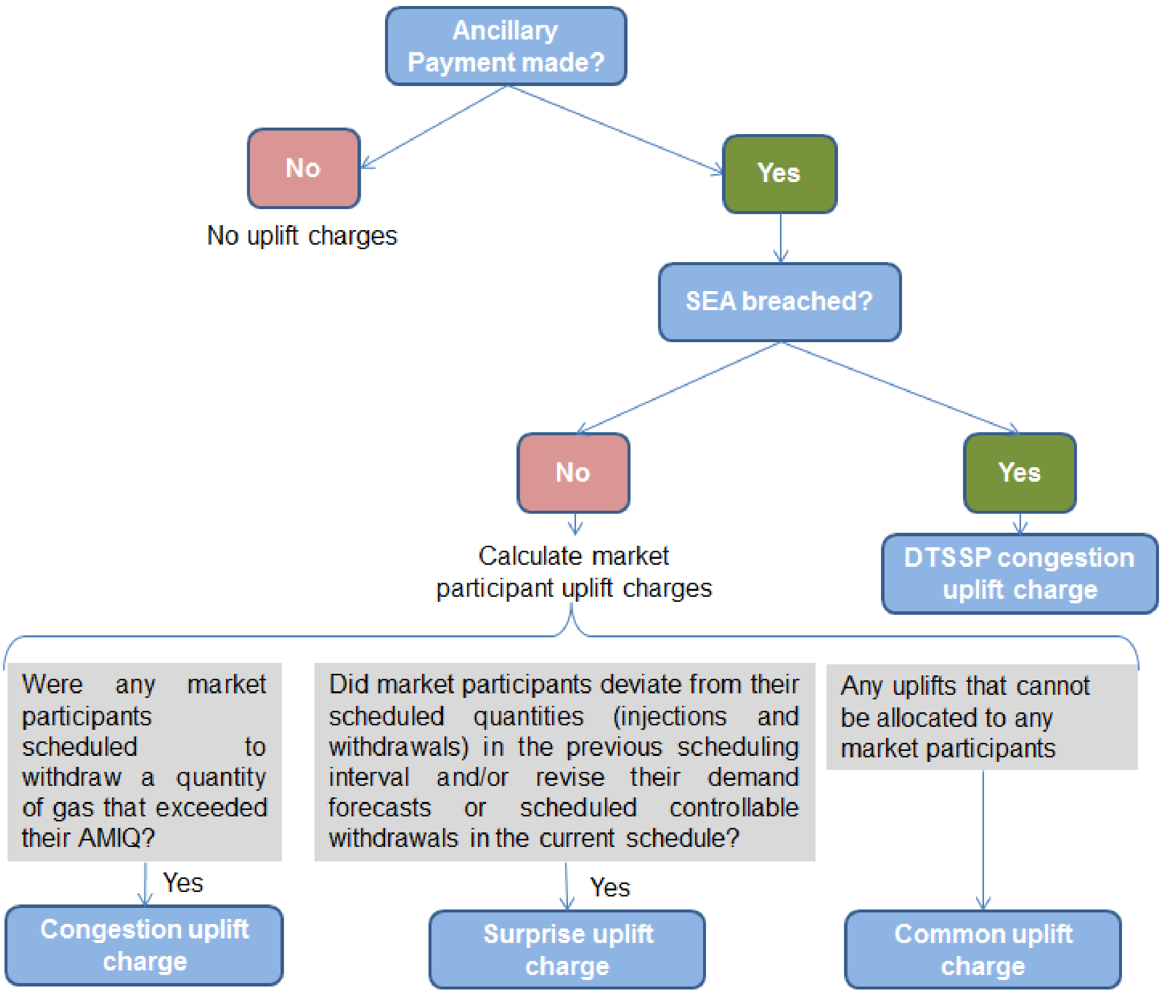
2. surprise uplift;

3. common uplift; and

4. Declared Transmission System Service Provider (DTSSP) congestion uplift.

The process for determining each of these uplift charges is outlined in the figure below and discussed in more detail below the figure.

Figure F.5 Overview of the process for determining uplift charges



Source: AEMC analysis.

Congestion uplift charges are levied on a market participant if that market participant is scheduled to withdraw a quantity of gas that exceeds its Authorised Maximum Interval Quantity (AMIQ)[696] for that scheduling interval and the system is congested resulting in a positive ancillary payment. Allocations of congestion uplift payments are based on market participants' share of total congestion uplift quantity using detailed algorithms by AEMO.[697]

Surprise uplift charges are levied on market participants when they are considered to have taken actions to "surprise" the market in a way that increases costs. Specifically, a market participant is liable for surprise uplift if either or both of the following conditions are met during times ancillary payments had to be made:

- the market participant deviates from its scheduled quantities (injections and withdrawals) in the previous scheduling interval; and/or
- the market participant revises its demand forecasts or scheduled controllable withdrawals in the current schedule.

As with congestion uplift payments, allocations of surprise uplift payments are based on market participants' share of total market surprise uplift quantity, calculated using detailed algorithms by AEMO.[698]

Common uplift payments include uplifts that cannot be allocated to any market participants via congestion or surprise uplift, for example costs associated with AEMO's excessive demand forecast overrides.[699] Allocations of common uplift payments to market participants are based on their share of total system withdrawal quantities.

DTSSP congestion uplift payments are allocated to the DTSSP where it can be determined that the DTSSP has contributed to congestion by not making available the relevant plant and the associated pipeline capacity as required under the SEA (ie the agreement it has with AEMO). For example, this could be due to additional congestion resulting from an unplanned outage of a critical plant where the outage can be attributed to lack of maintenance of the plant in accordance with the SEA.

696 Each market participant's AMDQ uplift hedge is converted to schedule interval quantities using their nominated AMIQ profile (ie how much AMDQ that participant expects to use in each schedule interval) to effectively create a hedge generated on an interval basis.

697 The AEMO algorithms for calculating a market participant's congestion uplift quantity are outlined at: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, pp. 92-94.

698 The AEMO algorithms for calculating a market participant's surprise uplift quantity are outlined at: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, pp. 90-92.

699 Prior to issuing the pricing and operating schedules, AEMO prepares hourly forecasts for uncontrollable withdrawals based on weather forecasts from the Bureau of Meteorology and compares these with the aggregate demand forecasts provided by all market participants. If they differ, AEMO determines whether to override the market participants' aggregate demand forecasts. See: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, p. 45

F.3 DWGM rule changes

Section 295(3) of the NGL provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction. To-date all rule change requests have been made by AEMO and a summary of these is shown in the table below.

Table F.1 DWGM rule changes

Determination date	Rule change	Brief Description
11 December 2014	Removal of Force Majeure Provisions in the DWGM	Clarifies how the market is to operate in times of market stress, facilitating more accurate decisions and appropriate risk management practices.
27 November 2014	Portfolio Rights Trading[700]	The Commission determined not to make the proposed rule as a result of the following factors: revised cost of implementing Portfolio Rights Trading; revised estimate of the timeframe for implementing Portfolio Rights Trading; and the, then, forthcoming Victorian gas market review.
25 August 2011	Various Hedging Instruments in the Declared Wholesale Gas Market	• Allowed participants to renominate AMDQ and AMDQ cc between system injection points that are close proximity injection points during the gas day; • Allowed participants to renominate their AMIQ profiles during the gas day for future scheduling intervals in that gas day; • Provided participants ability to nominate injection hedges (IHNs) and agency injection hedges (AIHNs) collectively to close proximity injection points (CPPs) rather than to system injection points; and • Pushed back the timeframes for participants to submit IHNs, AIHNs and AMIQ profiles to AEMO so that they must be submitted by one hour before the start of the gas day.
4 November 2010	Calculation of Interest for Gas Markets	AEMO to continue to calculate interest using a simple interest methodology.
16 December 2010	Dandenong Liquefied Natural Gas Storage Facility	Partially liberalised the operation of the Dandenong LNG storage facility.

700 In short, a PRT mechanism was proposed to allow market participants to more readily carry out short term trades of the benefits attached to AMDQ and AMDQ cc, without changing the physical ownership of AMDQ and AMDQ cc or any curtailment rights associated with them.

20 May 2010	Prioritisation of Tied Controlled Withdrawal Bids	Changed the tie-breaking rules that AEMO uses to schedule gas so that, where multiple controllable withdrawal bids were considered to be "equally beneficial" to the market, controllable withdrawal bids would be prioritised over other bids if the bidder held AMDQ units. Previously, multiple controllable withdrawal bids considered to be "equally beneficial" to the market were scheduled on a pro-rated basis.

F.4 DWGM Market Participants

The following table lists the registered participants in the DWGM as at April 2015.

Table F.2 DWGM market participants

Shippers	Users
Adelaide Brighton Cement, AETV Power, AGL, Alinta, Aurora, Aus Gas Trading, Australian Pacific LNG, B P Australia, BHP, Boyne Smelters, Braemar Power Project, Coogee Energy, Covau, CS Energy, EnergyAustralia, ERM, Incitec Pivot, International Power, Lumo Energy, MMG Century, Momentum Energy, Mount Isa Mines, OneSteel, Orica, Origin Energy, Pelican Point, Qenos, QER, Queensland Alumina, Queensland Magnesia, Red Energy, Santos Direct, Simply Energy, South Australian Water Corporation, South West Qld Producers, Southern Natural Gas Development, Stanwell Corporation, Synergen Power, Tas Gas, The Australian Steel Company, Visy Paper	ActewAGL, Adelaide Brighton Cement, AGL, Alinta Energy, Aurora Energy, BP Australia, BHP Billiton, BlueScope Steel, Bradmill, Click Energy, Commonwealth Steel, Covau, Delta Electricity, Ecogen Energy, EDL CSM, Endeavour Coal, EnergyAustralia, Ergon Energy, ERM, Gascor, GOEnergy, Lumo Energy, M2 Energy (T/As Commander Power), M2Energy (T/As Dodo Power & Gas), Momentum Energy, NovaPower, OneSteel, Orica, Origin Energy, Pentair Water Solutions, Qenos Pty Ltd, Red Energy, Santos, Simply Energy, Snowy Hydro, SOU Agent – TXU, Stanwell Corporation, Visy Paper
Pipeline owners	**Producers**
Allgas Energy, Anglo Coal, APA, APT Petroleum, AusNet, Australian Gas Networks, Bass Gas, Coastal Pipelines, East Australian Pipeline, Epic Energy, Gas Pipelines Victoria, Jemena, Multinet, SEA Gas, Tasmanian Gas Pipeline, The Albury Gas Co, Vic Gas Distribution	AGL, Australia Pacific LNG, BHP Billiton, Esso Australia Resources, Origin Energy, QGC, Santos, Woodside
Storage Providers	**Other**
AGL, APA, EnergyAustralia	AEMO, Central Ranges Pipeline, Envestra, Australian Power and Gas, Newgen Power, CitiPower

Source: AEMO data.

G Operation of the Gas Supply Hub

G.1 History and policy objectives of the gas supply hub

In December 2012, SCER announced that a new voluntary brokerage hub would be established at Wallumbilla by March 2014.[701] SCER requested AEMO develop this hub to enhance transparency and reliability of gas supply by creating a voluntary market that offers a low-cost, flexible method to buy and sell gas at interconnecting transmission pipelines.[702]

Wallumbilla was selected as the location for the supply hub because it is located in close proximity to significant gas supply and demand and is a major transit point between Queensland and the gas markets on Australia's east coast. Wallumbilla marks the intersection of the Roma Brisbane Pipeline (RBP), the South West Queensland Pipeline (SWQP) and the Queensland Gas Pipeline (QGP).

The figure below illustrates how Wallumbilla acts as a transit point for major gas fields and a supply point for demand centres in Gladstone and Brisbane, and is located near gas storage facilities and gas-powered generation, making it a natural point of trade.

Figure G.1 Location of the Wallumbilla supply hub

Source: AEMO, Gas Supply Hub Industry Guide, March 2014, p. 2.

AEMO was given the responsibility for the design of the hub and at the time of developing it stated that it expects the implementation of this hub to:[703]

701 SCER Communiqué, 14 December 2012.

702 AEMO website, available at: http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub.

703 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p. 4.

- enhance the transparency of gas trading;
- improve the ability of participants to allocate and price gas efficiently in the short term;
- support the efficient trade and movement of gas between regions; and
- support the development of a financial product that can be used to manage risk.

Overall, the supply hub was established to provide a reference price that would support a financial derivative market to manage risk, guide investment and transactions decisions, facilitate trading through standardisation of contracts, and promote secondary pipeline capacity trading.[704]

G.2 Design and structure of the gas supply hub

This section provides an overview of the design and structure of the Wallumbilla GSH. It covers how parties can participate in the GSH, the products currently on offer and the key design features.[705]

G.2.1 Participation in the market

To participate in the GSH an organisation must become a member of the exchange and register to as a participant in one, or more, of the following three categories:

1. Trading participant: authorised to place orders and form transactions through the exchange and can gain authorisation to enter into reallocations.[706]
2. Reallocation participant: authorised to enter into reallocations only. Can gain access to the exchange by registering in the category of viewing participant.
3. Viewing participant: authorised to view orders and transactional information through the trading exchange. Does not have any trading or financial involvement in the market.

Trading participants and viewing participants have access to the exchange and can view prices and quantities of active orders and recent transactions.

Participants must also provide sufficient bank guarantees to cover the market's exposure to their trading activities and a member's trading limit is equal to the bank guarantees provided. Participants are not permitted to share collateral between other markets that AEMO operates and a new bank guarantee is required for the GSH.[707]

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704 ibid, p. 4.

705 Unless otherwise stated, the information in this section references: AEMO, *Gas Supply Hub Industry Guide,* March 2014.

706 A reallocation is a financial arrangement between two market participants and AEMO to transfer settlement commitments between the market participants.

707 AEMO, Gas Supply Hub Frequently Asked Questions, available at: http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub/FAQ

G.2.2 Products

Products traded are for physically delivered gas, the terms of which include a warranty that the transacting parties have the necessary rights at the delivery point to give effect to the delivery and receipt of the gas.

Specifically, products listed on the exchange are for the sale and purchase of gas delivered at one of the three major connecting pipelines at Wallumbilla, ie, the RBP, the QGP and the SWQP pipelines (as outlined in Figure G.2 above). A 'trading location' has been established for each of these pipelines by grouping delivery points (either physical or virtual) to which gas is delivered and where title is transferred from a seller to a buyer.

The four trading products currently on offer are summarised in the table below. All products are currently available separately for each of these three trading locations.

Table G.1 GSH trading products

Product	Trading Window	Gas Delivery
Balance-of-day (today)	Available for trading on the gas day. Delivery of gas occurs from the hour after the time of the transaction through to the end of the gas day.	Each individual transaction must be delivered
Day-ahead (tomorrow)	A gas day product that is available for trading on the day prior to the delivery gas day.	
Daily (two to seven days ahead)	A gas day product that is available for trading between 2 and 7 days prior to the delivery gas day. All other specifications for the product are same as the day-ahead product except that netting is applicable (as described in G.2.3 below).	Delivery obligations are netted.
Weekly (next four weeks)	Trading commences on a Saturday four weeks prior to the commencement of the weekly delivery period. Trading closes on the Friday (2 days) prior to the prior to the commencement of the weekly delivery period.	

Source: AEMO, *Gas Supply Hub Exchange Agreement*, Version No. 2.0, 13 April 2015.

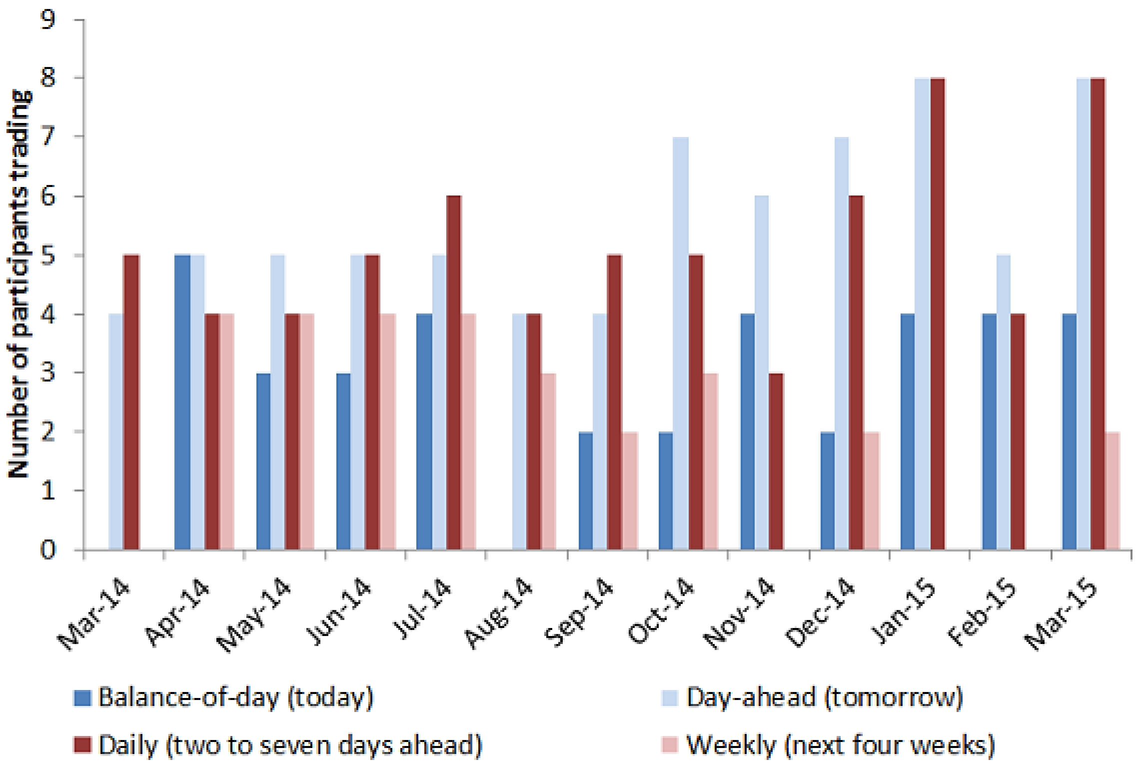
Note: We understand from AEMO it is also intending to list a monthly forward dated product later in 2015.

These products are available on a short-term basis and provide trading participants with an option for balancing their gas portfolio requirements around long-term agreements. The transaction quantity for all products, including balance-of-day and weekly, is measured as a quantity per gas day (GJ/day). Minimum quantities for the product are detailed in the product specifications contained in the exchange agreement. Unless otherwise agreed between the parties, gas delivery is at a constant hourly flow rate for the period of a transaction.

Trading participants also have the opportunity to trade capacity, which is facilitated by the exchange. Specifically, the exchange includes a capacity listing service but actual capacity-related transactions must be bilaterally negotiated and settled.

Figure G.2 illustrates the monthly trade activity on the Wallumbilla supply hub by product, since market start.

Figure G.2 Monthly trade on the Wallumbilla supply hub by product, March 2014 – March 2015



Source: AEMC analysis on AER, Wholesale Statistics.

G.2.3 Key design features of the Wallumbilla supply hub[708]

This section details the key design features of the Wallumbilla GSH. It covers: the exchange agreement; how gas is traded; the concept of delivery netting; settlement;

708 Unless otherwise stated, the information in this section references: AEMO, *Gas Supply Hub Industry Guide*, March 2014.

delivery variances; the lack of physical connection at the hub; and market fees and participant costs.

Exchange agreement

In accordance with the NGR, the supply hub has an 'exchange agreement' that sets out the standardised terms of participation in the supply hub and the terms governing transactions entered into through the exchange. The exchange agreement contains the trading, delivery and settlement obligations common to all products. It also outlines the product specifications, which are schedules to the exchange agreement that contain details unique to each product.

The NGR itself contains relatively little detail on the GSH, compared to the STTM and DWGM. The NGR covers: the fees recoverable by AEMO; the appointment of an operator by AEMO; how payments are determined; membership and participation; the exchange agreement; and the market conduct rules.

Trading of gas

Participation in the supply hub is voluntary and designed to complement existing bilateral gas supply arrangements and gas transportation agreements. Trades are matched anonymously, although there is also a facility for participants to agree bilaterally to a transaction on standard product terms and then register the transaction for delivery and settlement. This allows participants a lower transaction costs option for trading gas and also allows the counterparty risk to be lowered.

In transacting on the exchange the seller commits to supply gas at the trading location and the buyer agrees to take receipt of that gas at the trading location.

Trading hours are between 9.00am to 5.00pm on the Wallumbilla GSH and the gas day start time on the Wallumbilla GSH is consistent with the Brisbane STTM hub (8.00am).

Within a trading location, there may be multiple delivery points.[709] Once transacted, the delivery points specified in the trade will be the location for gas delivery. Participants are responsible for arranging the delivery of gas at the hub using existing contractual supply and transportation agreements. The pipeline operator schedules the delivery of gas at the trading location based on nominations submitted by participants.

Delivery netting

As noted in section G.2, a delivery netting service is provided for all products traded more than one day from delivery. Rather than deliver gas against each individual transaction, delivery netting produces a single net gas delivery obligation for each trading participant across their relevant transactions. Netting applies to gas delivery obligations only and all transactions must be financially settled.

709 Delivery points are virtual points or at a junction on the QGP, RBP and SWQP.

Delivery netting involves AEMO determining the net delivery position for each participant at the end of trading. AEMO then matches participants with offsetting delivery positions based on an algorithm that minimises the number of transactions that need to be delivered.[710]

A simplified overview of how the concept of delivery netting operates in practice is outlined in Box G.1.

Box G.1 Delivery netting

Suppose there are three market participants that conduct the following trades with one another:

- Trade 1: Participant A buys 5 TJ from Participant C;
- Trade 2: Participant C buys 15 TJ from Participant B; and
- Trade 3: Participant B buys 5 TJ from Participant A.

AEMO would then offset buy and sell exchange transactions to determine a net delivery position for each participant as follows:

Trade	Participant A	Participant B	Participant C
1	5 TJ	-	-5 TJ
2	-	-15 TJ	15 TJ
3	-5 TJ	5 TJ	-
Net delivery	Zero	Sell 10 TJ	Buy 10 TJ

AEMO determines each trading participant's net delivery position by aggregating buy and sell transactions across all netted products for each trading location and gas day.[711] AEMO matches net buy and net sell positions to form a gas delivery schedule. Trading parties remain anonymous until the gas delivery schedule is issued by AEMO to participants.

The netting of gas delivery obligations eliminates the requirement to deliver offsetting delivery obligations (delivery and receipt) that could act as a hurdle to efficient portfolio management. Delivery netting also reduces the administration associated with nominations, measurement and communication of actual gas deliveries.

710 AEMO, *Detailed design for a Gas Supply Hub at Wallumbilla*, 19 October 2012, p. 21.

711 The delivery netting process runs every day after the end of trading. Transactions covering the gas day two days in the future are retrieved for the calculation of the net delivery position. AEMO will determine each trading participant's net delivery position and then match those net delivery positions amongst participants to form a delivery schedule. AEMO will then issue a gas delivery schedule to trading participants so that they can carry out their gas delivery obligations.

Settlements

The Wallumbilla GSH features a centralised settlement model to settle transactions with AEMO facilitating payments from buyers to sellers. This involves collating transactional information from the trading system, collating delivery information from trading participants, calculating settlement amounts, and issuing statements.

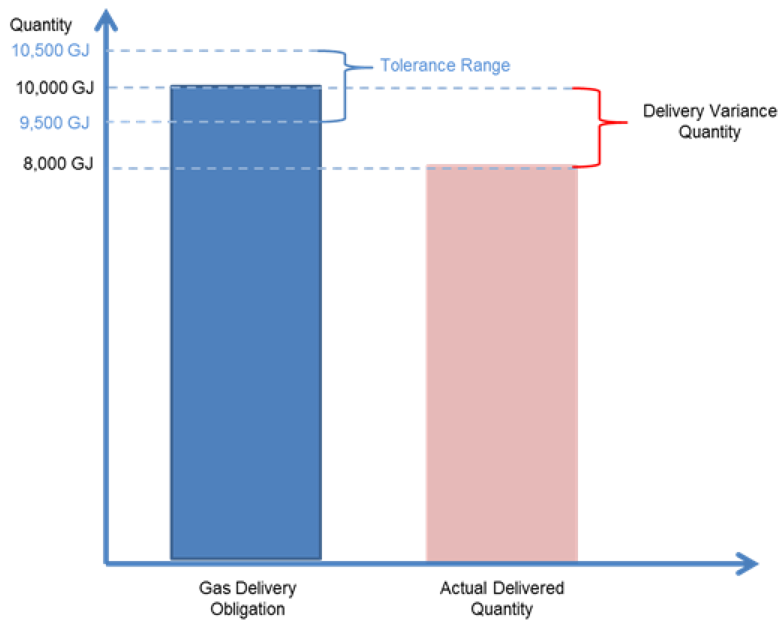
As noted earlier, market participants must maintain credit support to cover the exposure associated with their transactions.

Settlement of delivery variance

'Delivery variance settlement' is a procedure that AEMO administers to facilitate the transfer of compensation between the buyer and seller for a variation between the gas delivery obligation and the actual delivery.

AEMO defines a tolerance for variations in actual delivered quantity of five per cent of the gas delivery obligation (for both the over- and under-delivery of gas). Figure G.3 illustrates this using an example where the seller (delivering participant) is not able to deliver the contract quantity and the delivery variance quantity is outside the permitted tolerance.

Figure G.3 Delivery variance



Source: AEMC analysis.

Regardless of whether the delivery variance quantity is outside of the tolerance, the delivery variance quantity is settled at the delivery price. The delivery price is dependent on the whether netting is applicable to the gas delivery obligation:

- average price for netted products (as outlined above), or

- transaction price if product is not netted.

Additionally, if the delivery variance quantity is outside the tolerance then the settlement is adjusted so that the defaulting party compensates their counterpart. The party at fault compensates their counterpart for 25 per cent of the value of the variation quantity.[712]

In determining the party at fault, AEMO considers the reason for the variation, eg:

- a gas producer (delivering participant) may have failed to inject gas into the pipeline in accordance with their gas delivery obligation – the delivering participant was responsible for the delivery variation; or
- a shipper (receipting participant) may have failed to make nominations to the relevant pipeline operator in accordance with their gas delivery obligation – the receipting participant is responsible for the delivery variation.

An example of how this compensatory mechanism works for delivery variance quantities outside of the tolerance range is illustrated in the box below.

Box G.2 Delivery variance quantities - compensatory mechanism

Suppose that Figure G.3 above represents a situation where Trader A has agreed to sell 10,000 GJ of gas to Retailer X at a price of $6/GJ. Under this hub transaction, Trader A will receive a transaction payment of $60,000 from Retailer X.

However, suppose that Trader A (ie the seller) is not able to deliver the entire contract quantity to Retailer X (ie buyer). Specifically, receipt point allocation for Retailer X is 2,000 GJ lower than its nomination and so Trader A must pay back for the gas it did not deliver to the hub. This delivery variance charge is calculated as:

- $12,000 (ie 2,000 GJ x $6/GJ).

Further, given the delivery variance of 2,000 GJ is outside of the five per cent tolerance (ie 500 GJ), Trader A must make pay delivery variance charge to Retailer X. This is calculated as:

- $3,000 (ie 2,000 GJ x $6/GJ x 25 per cent).

Overall, Trader A is paid a total of $45,000 by Retailer X for the 8,000GJ it delivered to the hub (or, equivalently $5.625/GJ). This is calculated as:

- Hub transaction payment less delivery variance charge less delivery variance compensation, ie $60,000 - $12,000 - $3,000.

712 No adjustment is processed if force majeure (pipeline issue only) applies to the delivery failure.

The delivery payment and charge settlement mechanism is the only remedy available for a breach of a participant's delivery obligations. The fixed compensation mechanism may under or over compensate a participant for their actual direct costs associated with the delivery default. However, the fixed compensation mechanism provides certainty of the trading risks to participants prior to entering into a hub transaction and is simpler to administer than the determination of damages on a transaction by transaction basis.

Lack of physical interconnection

As noted above, the Wallumbilla supply hub has three physical trading locations which are the RBP, SWQP and the QGP. While these pipelines are connected, they operate under different pressures and contractual arrangements by two pipeline owners (ie Jemena for QGP and APA Group for RBP and SWQP). As such, there is no single physical location that allows shippers to trade across the Wallumbilla hub.[713]

The fact that not all of the pipelines servicing Wallumbilla are physically connected was a reason why AEMO developed three separate trading nodes at Wallumbilla.[714]

The lack of physical interconnection, coupled with the fact that only a few participants are currently in a position to transport gas between the trading nodes (ie because they have the necessary transportation and ancillary services contracts in place), means that the pool of potential buyers and sellers is divided across the three trading nodes. The division of what is already a relatively small group of buyers and sellers limits the degree of liquidity that can be achieved in the market and could also give rise to significant price variations across the three trading nodes.[715]

While we note that the vast majority of trades to date have occurred at the RBP node,[716] as can be seen in Figure G.4 those trades occurring at the SWQP node do not appear to be significantly different to those at the RBP node. However, this is not to say this will continue to be the case, particularly as trades emerge at the QGP pipeline. Further, the pattern of prices in the period following the first exports of LNG from Queensland in late 2014[717] differs notably from the period preceding these exports.

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713 AEMO, *Gas Supply Hub: Cost and Scoping Report*, May 2012, p. 18.

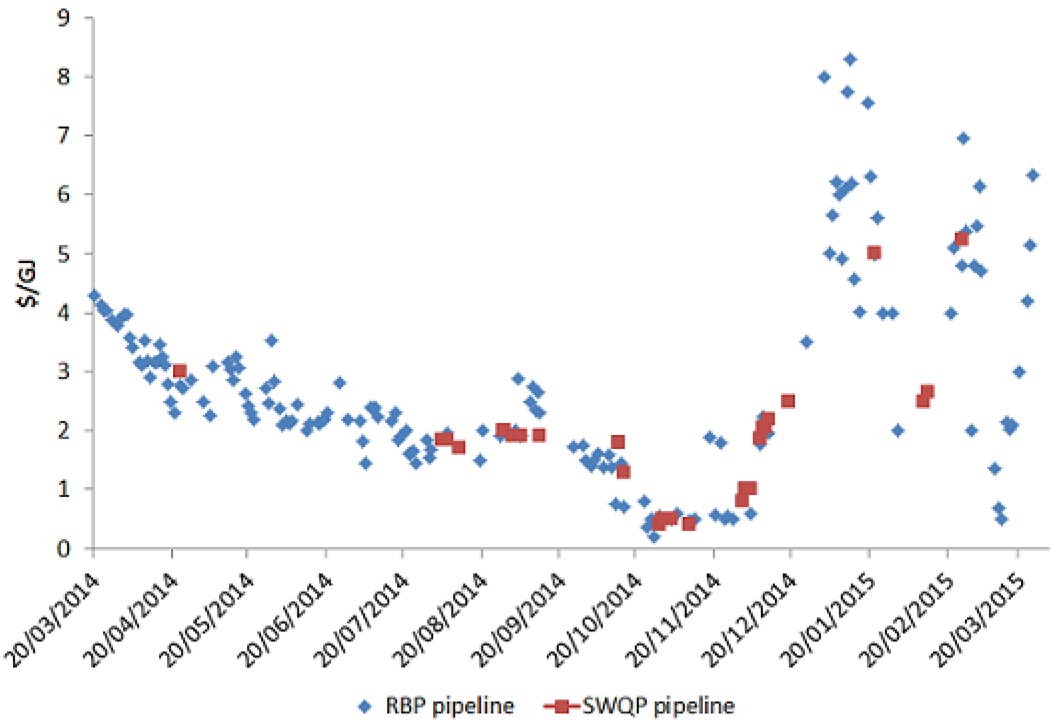
714 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 62.

715 ibid, pp. 62-63.

716 We understand that most trades have occurred at the RBP delivery point with trading between participants who have excess gas from gas-fired generation selling to opportunistic buyers who have the capacity to transport and store this excess gas.

717 BG Group began loading its first LNG cargo from QCLNG on 28 December 2014. See: QGC website, available at: http://www.qgc.com.au/news-media/NewsDetails.aspx?Id=5630.

Figure G.4 Majority of trades have occurred to date at the RBP node



Source: AEMC analysis on AER, Wholesale Statistics.

AEMO is aware of this potential limitation and has noted it could, to some extent, be addressed if the brokerage model was extended to include a new range of hub services that would enable parties that do not currently have the contractual rights to transport gas across the hub to do so. The two hub services that AEMO has identified as being of particular importance in the initial stages of the supply hub's life are redirection and compression services. Other hub services AEMO has noted could evolve over time are balancing, storage and processing services.[718]

Market fees and transaction costs

Trading, reallocation and viewing participants are required to pay a fixed participation fee, determined in accordance with their participation category. These annual fees are currently, $14,500, $9,000 and $5,500 for trading, reallocation and viewing participants, respectively.[719]

Trading participants are also required to pay a variable transaction fee based on the quantity of transactions they enter into through the exchange. These variable transaction fees are currently $0.03/GJ for daily products and $0.02/GJ for weekly products.[720]

718 AEMO, *Gas Supply Hub – Cost and Scoping Report*, 4 May 2012, p.14.

719 AEMO, *Gas Supply Hub – Exchange Fees*, 20 March 2014, p. 1.

720 ibid, p. 1.

H Submission Summaries

Table H.1 summarises stakeholder submissions to the AEMC's Discussion Paper released in February 2015. Table H.2 summarises stakeholder submissions to the AEMC's Stage 1 Draft Report released in May 2015. Copies of submissions can be found on the AEMC's website www.aemc.gov.au.

Table H.1 Discussion Paper: Submission summaries

Stakeholder	Comment
Markets: complexity and cost	
Adelaide Brighton, pp. 2-3	STTM has reduced average cost of gas for large users by allowing users to use a portfolio approach to procurement. Intraday trading would add to costs. Gas users can adjust nominations and use MSVs to balance position, which negates need for intraday trading.
Adelaide Brighton, p. 4	More work should be performed on determining whether to remove the DWGM and establish an STTM in Melbourne.
Adelaide Brighton, p. 3	Intraday trading in the STTM would be of limited benefit to customers and would increase the level of resources required to participate in the STTM.
AGL, p. 1	Complexity and transaction costs overwhelm any value to be had from trading in the STTM facilitated markets. Simplification is required, eg consideration should be given to dispensing with the pricing functionality in the STTMs and relying on physical balancing and correct nominations by participants (with penalties for material deviations).
AGL, p. 3	Wallumbilla gas supply hub has facilitated short-term trades in gas by eliminating the overheads of contractual and term sheet negotiations associated with spot transactions.
AGL, p. 5	The DWGM is best left unchanged, as the costs associated with change are likely to outweigh the benefits. Nevertheless, as there is significant complexity and risk in ancillary payments and uplift charges, AGL would welcome a review of these charges with the aim of reducing market participants' transaction costs and pricing risks.

Stakeholder	Comment
Alinta, p. 6	Alinta does not expect the construction of additional hubs such as Moomba to materially change the nature of trading activity in the area. However, there is some contention that trading hubs may not actually be needed if existing transport costs were not so excessive or if alternate market structures such as a carriage arrangement were in effect.
Alinta, pp. 5-6	Alinta is supportive of the review investigating what benefits could be revealed through longer term options such as increased integration between facilitated markets and whether three distinctly separate gas markets remains fit for purpose given the relatively small volume of gas traded. Regardless, there are areas that are worthy of resolution now: • greater alignment of market parameters between facilitated markets; • common gas day; and • prudentials.
Alinta, p. 8	Transaction costs are high due to contractual and administrative burdens associated with trades involving gas pipelines.
Alliance of industry associations, p. 7	Within the alliance of industry associations, an individual association suggests streamlining and simplifying the STTM registration process to encourage more participants.
APA, pp. 9-10	The STTM design is overly complex for the primary gas balancing function it performs. The complexity inherent in the STTM drives significant market operating costs and there is little evidence of additional retailers entering the market. The STTM should be simplified to be a balancing market that provides for competitive balancing services through a tender process.
Arrow Energy, pp. 7, 8	Australian gas markets are currently disparate, creating inefficiencies or hurdles to transacting. Arrow is of the opinion that a single market structure dealing with all transaction elements, from production to use, is critical. Impediments to participation include: market inconsistencies, complexities and costs; lack of physical pipeline interconnection and access to transportation capacity in some areas; the continued prevalence of longer term contracts (usually bespoke); lack of standardised contract terms; and basis risk resulting from differing market dynamics.

Stakeholder	Comment
Australian Energy Regulator (AER), pp. 2-3	Accuracy and timeliness of data and demand forecasts in the STTMs shortly after to their commencement led to ad hoc outcomes and inefficient prices. More recently, the AER has reported significant improvements in these areas.
AER, p. 3	Ongoing monitoring work by AER is lowering costs in the STTM.
Australian Petroleum Production & Exploration Association (APPEA), p. 3	Recommends investigation of means to more closely align facilitated markets.
Australian Pipelines and Gas Association (APGA)	APGA considers that the STTM hubs do not deliver value to market participants. Internal costs incurred by market participants in setting up and managing systems to interact with the STTM, in addition to the 8c/GJ transaction costs present a burden for participants. The STTM and DWGM are primarily balancing markets, designed to complement, not inform or replace, long term contracting arrangements. The prices in these markets are not commodity supply price, rather the price of the imbalance on the day, in that market. There are opportunities for improved integration across the markets, such as harmonising: • gas day start times; • price caps; and • terminology. Further, counteracting MOS in the STTM arises because the STTM is assumed to not have physical limitations to delivering gas to Sydney and Adelaide. APGA contends this is not a design fault, but rather a price signal for change and further investment. APGA is also concerned about the inability of the market operator to correct STTM prices in the event of pipeline information error or failure.
BHP Billiton, p. 2	Reform initiatives should be harmonised across all states (by leveraging AEMO's processes, systems and implementation experience).

Stakeholder	Comment
Energy Supply Association of Australia (ESAA), p. 1	A key area for consideration is how to minimise the costs and risks associated with participating in the facilitated trading markets.
ESAA, pp. 3-4	Facilitated markets provide participants with access to gas in the initial phase of market entry. But long-term contracts for gas supply and transportation (outside of the facilitated markets) are ultimately required to manage the significant price risk associated with operating in those markets. The ability of market participants (and new entrants) to rely purely on the facilitated markets for gas supply will continue to be impeded while they create significant price/supply risk.
ESAA, p. 4	Differences between the DWGM and STTM can potentially increase costs for participants operating across multiple jurisdictions. There is merit in examining: • the creation of a single gas day; • the consolidation of prudential requirements; and • harmonisation of gas market parameters.
ESAA, p. 5	The facilitated markets are quite costly on a $/GJ traded basis.
EnergyAustralia, p. 2	The three fundamentally different types of facilitated market need to be better aligned (although this is not to say that a single approach is necessarily required).
Epic Energy, p. 2	The STTM and DWGM are balancing markets and should not be considered wholesale markets. The DWGM and STTM price reflects the value of imbalance in the market and not the value of gas for that region, especially in the South Australian hub where power generation loads are excluded.
ERM Power, p. 7	The DWGM has complex elements, which reduces information transparency and ability to manage trading positions and market outcomes. Efficiency could be improved by harmonising gas day start times.
ERM Power, pp. 9-10	ERM questions the net benefits of introducing a single trading zone/single product model.

Stakeholder	Comment
ERM Power, p. 10	The minimum parcel size at Wallumbilla may prevent smaller participants from trading. GSH fees are also too high and should be reduced.
GDF Suez Australian Energy (GDFSAE), pp. 8-10	The existence of multiple hub designs creates complexities and inefficiencies. While the WGSH is purpose built and continues to evolve, the remaining facilitated hubs require more development to manage challenges facing the market and to facilitate the optimal level of trade outside of bilateral contracts. Areas for investigation are: • rationalising market design; • coordinating dispatch; • using clear, understandable within day charges and better management of ex-post pricing; • better use of balancing and maximising trade; • signalling the value of capacity and services inside hubs; • more efficient price signals; • limiting the role of pipeline and facilities within hubs; • consolidating prudential regimes; • developing gross indices; • facilitating financial trade at Wallumbilla; • identifying preferred conditions for the Moomba Gas Supply Hub; • auctioning capacity credits; and • the use of backhaul for the purposes of calculating pipeline capacity.

Stakeholder	Comment
Group of leading energy companies and major users (GLECMU), p. 1	A challenge today is the fragmented nature of Eastern Australian gas markets, including existing trading and capacity arrangements, and the difficulty in establishing an agreed and coherent framework that best meets the needs of the market.
GLECMU, p. 3	Multiple market designs make trading complex and inefficient for participants with each market characterised by specific and enduring limitations.
Lumo Energy, pp. 3-4	Markets are allowing transactions to occur and are operating satisfactorily. While there may be some minor changes that are required, major changes need to demonstrate a clear case for being made.
Lumo Energy, pp. 3-4	There are no real barriers to entry to using the wholesale markets. While adding an intraday trading mechanism would add cost and complexity, it would provide market participants with an avenue to improve the manner in which they manage their deviations of the trading day.
Lumo Energy, pp. 9-10	Supports the development of a single product at Wallumbilla. This will facilitate the development of longer term trading products, which Lumo supports.
Major Energy Users (MEU), p. 6	Facilitated markets are complex, but complexity can result from attempting to ensure markets operate in long term interests of consumers.
Manufacturing Australia, p. 6	A functioning market should have more suppliers, as well as more gas supply. Transparency and opening of the domestic market to competitive functioning is imperative to restoring confidence in the market.
Origin Energy, pp. 4-5	There is no need to harmonise the markets under one single design. There is, however, possible scope to coordinate certain elements: • harmonise gas days, including with reference to the NEM day; • netting prudential requirements; • coordinating market parameters (eg market price cap); and • formulation and presentation of information.

Stakeholder	Comment
Qenos, p. 4	Gas Supply Agreements would be more easily made if information was centralised and more easily accessed.
Qenos, p. 5	Allowing for the full settlement of Markets Schedule Variations (MSV) through the STTM Settlement System would negate the need for individual parties to put in place separate documentation with every other market participant for MSV transactions. It would negate the need for credit checks and credit support arrangements between individual market participants for MSVs.
QGC, p. 6	There is a lack of harmonisation across facilitated markets of key features including trading day definition, consistency of trading periods and settlement processes.
Santos, p. 1	Standardisation of facilitated markets would reduce costs, barriers to entry and basis risk among regions. It would facilitate more players in the market and hence a more liquid secondary market. Consideration should be given to standardising all balancing markets so there is one model across all regions. Santos agrees with a number of other alignments, such as standardisation of the gas day and minimum market price caps.
Stanwell Corporation, pp. 1-2	A well-functioning east coast gas market could be modelled on the NEM. This could feature the following characteristics: • Participants providing injection and withdrawal bids to AEMO. • Gas volumes scheduled by AEMO. • AEMO calculating and publishing gas prices at regular intraday intervals. • Transportation costs estimated by AEMO in advanced and charged to shippers. • Gas pipeline investment and revenue regulated by the AER and buyers pay usage charges based on consumption. • AEMO operating a separate balancing market based on offers to provide balancing services by participants and pipelines, with the cost recovered from consumers. • New producers or consumers connecting to the transmission or distribution network through a connection agreement rather than through specifying a pathway.

Stakeholder	Comment
Stanwell Corporation, p. 4	Complexity and cost of operating under various market arrangements is a barrier to entry.
Markets: liquidity	
Epic Energy, p. 4	Epic Energy supports the introduction of a trading location at Moomba and considers it would provide a more transparent market place to non-Queensland market participants.
Adelaide Brighton, p. 2	Facilitated markets improve liquidity, providing an additional option for procuring gas.
AGL, p. 2	The physical configurations of the individual hubs are not consistent with the fundamental assumption made when the STTM markets were designed (that there are no or minimal network constraints within the distribution network). The existence of phenomena such as counteracting MOS suggests that this assumption does not hold under all circumstances and flow situations.
AGL, p. 3	STTMs require that the ex ante price and scheduled offers are locked down some 18 hours before the start of the gas day. Deviations are the result of changing conditions from that time. However, AGL would caution against intra-day renomination functionality, given its complexity. Instead, a MOS balancing service, and participants engaging in MSV trades may be appropriate.
Alinta, p. 7	Alinta is interested in exploring (as a long term policy option) a market carriage type arrangement with a single gas market with regional nodes (not dissimilar to the power market).
Alinta, p. 8	The market does not currently cater for short-term trades.
Alliance of industry association, pp. 6-7	Gas market solutions must reflect the full range of identified market-based reforms for the gas market, including: • consideration of a transitional national mechanism to require all stages of the gas value chain that have capacity available to provide an offer to the domestic market; • establishment of a daily balancing mechanism for the gas wholesale markets, as occurs in the electricity market; and • fast tracking the Moomba Gas Hub to facilitate the supply of gas by junior producers.

Stakeholder	Comment
Alliance of industry associations, p. 7	Within the alliance of industry associations, individual associations suggest: • incorporating MSV trading in the STTM in preference to intra-day trading; • a requirement for AEMO to balance the east coast gas market on a daily basis so that there is no NSW shortfall; • the development of a gas supply hub at Moomba; and • the development of a liquid forward market.
APA, pp. 18-19	APA supports the development of hub services at Wallumbilla to improve liquidity of the market, and is currently working with AEMO and other participants on the design of those services (to allow trading across the three pipelines and integration of the three trading nodes into a single point). Before proceeding with development of a second hub at Moomba, the impact on liquidity at Wallumbilla should be properly assessed. APA considers there may be merit in exploring options for a consistent market design across eastern Australia that would support trade across all markets. The design would rationalise existing structural elements into two key arrangements: • gas supply trading at gas supply hubs located at natural trading points; and • simplified market based balancing at demand centres.
Arrow Energy, p. 9	The WGSH has delivered improved liquidity. A more important benefit is the development of a transparent pricing point.
Arrow Energy, p. 9	Trading at RBP can impact trading on the STTM and vice versa.
Arrow Energy, p. 9	There are possible advantages and disadvantages to introducing the Moomba supply hub. It would add price transparency on hub transfer services and would identify constraints on any interconnected pipelines. However, multi nodal markets generally adversely impact liquidity.

Stakeholder	Comment
AEMO, p. 2	A GSH at Moomba is likely to provide participants with more trading options and, in turn, more liquidity in the secondary capacity trading market.
AER, p. 3	Occurrences of counteracting MOS may reveal Adelaide STTM design issues, justifying further investigation.
Australia Pacific LNG, p. 2	Supports the development of a more liquid wholesale spot and forward gas market. This may be facilitated by: greater consolidation and alignment in market design across regions; improved transportation access, including standardised terms; development of a daily reference gas price; development of longer term traded products including futures; development of additional hub services including balancing and pooling.
APPEA, p. 2	Relatively small size of the east coast gas market by international standards has historically placed limitations on the liquidity and complexity of gas markets.
APGA	Transmission pipelines have an important role in developing liquid, transparent and competitive wholesale markets, however further regulation is not the 'silver bullet' to further development of the markets. APGA considers that there are insufficient market participants to underpin a liquid and flexible eastern Australian gas market and additional Government intervention (and associated complexity) is not warranted.
BHP Billiton, p. 2	The market in eastern Australia continues to be dominated by long term confidential bilateral transactions. Increased market transparency and liquidity will improve the market’s ability to respond more rapidly to market developments and to send timely signals to encourage a response. BHP Billiton supports the current market reform initiatives that are being progressed across Australian gas markets.
BHP Billiton, p. 2	Supports the concept of transitioning or complementing the STTM and the Victoria spot market with a common supply hub model to promote the development of wholesale market liquidity. Hurdles to development include: • the small size of the market compared to international markets; and • barriers such as the complexity associated with entering the existing Victorian imbalance market.
ESAA, pp. 3, 5	To improve trading and liquidity and ensure the facilitated markets deliver value to market participants in the future, reducing transaction costs and minimising the pricing risks associated with participation is essential.

Stakeholder	Comment
ESAA, p. 5	The Brisbane hub suffers from structural limitations. This includes: a reliance on a single transmission pipeline; the inability to purchase gas from the hub unless a transportation contract on the pipeline is held; and the market design assumption that there are no constraints within the hub when this is clearly not the case. The evolution of the Wallumbilla GSH could further diminish the value of/need for the Brisbane hub in the future.
ESAA, p. 6	A Moomba GSH has the potential to facilitate improved participation and liquidity.
EnergyAustralia, p. 3	Supports the GSH at Moomba as a potential immediate priority. Lessons from Moomba and Wallumbilla should inform the Commission's wider analysis.
EnergyAustralia, p. 3	Review should focus on opportunities to align producer nomination times and market schedules, options to enhance intra-day flexibility, and the interaction between gas and electricity markets.
ERM Power, p. 9	While establishing a GSH at Moomba may reduce liquidity at Wallumbilla, the benefits of establishing a GSH at Moomba outweigh these costs.
GDFSAE, p. 2	Market liquidity and the opportunity to manage risks arising through market participation do not match participants' interests. The reasons for this include absence of integration, historical hub-by-hub developments, markets overly influenced by physical limitations, high entry and transaction costs, and focus on bilateral contracts and contractual strictures.
GLECMU, p. 3	Hubs should be designed to facilitate participation and liquidity. Presently, hub characteristics and design lead to a situation where gas retailers are likely to participate, with gas producers, industrial and commercial users and pipelines typically outside of these arrangements, and intermediaries choosing not to participate.
GLECMU, p. 3	Within day price signals, trading day definitions, consistency of trading periods, and settlement processes should be set so as to facilitate trade and support a more liquid market including encouraging the development of forward products.
Lumo Energy, p. 6.	Intraday trading in the STTM would provide significant benefits to the market.
Lumo Energy, pp. 10-11	A Moomba Trading Hub should be established.

Stakeholder	Comment
MEU, p. 4	Physical constraints exist at Wallumbilla. Moomba GSH has potential to ease shortages of gas and increase competition.
Manufacturing Australia, p. 6	AEMO should develop additional gas trading hubs, such as proposed at Moomba. All gas should be delivered, priced and traded at designated hubs and published against a benchmark price. As further pipelines and supplies are developed, other hubs can be added to the marketplace.
Manufacturing Australia, p. 8	The AER should extend the National Gas Access Arrangements to gas production facilities where they have monopoly positions so that all gas producers can have access on an equal footing. Governments should restrict the capacity of any one entity, joint venture, or partnership to control a large or dominating share of reserves, while promoting entry of new competitors from the point of resource control and extraction. The Federal Government should actively facilitate the entry of new competitors to break down existing concentration.
Origin Energy, p. 4	Focus for the GSH should be on improving participation and liquidity. A Moomba hub could facilitate this.
Origin Energy, p. 4	A valuable future development may be to encourage participation by non-physical participants such as financial institutions. This in turn will require balancing services to allow them to close out their positions, which is linked to a single trading product at Wallumbilla. Origin supports the current process to develop and assess the merits of a single product at Wallumbilla.
Origin Energy, p. 4	In light of the success of the Wallumbilla GSH, Origin suggests there is a strong impetus to cease operations of the Brisbane STTM.
Qenos, p. 5	Supports the development of the proposed GSH at Moomba.
QGC, p. 1	Wallumbilla Gas Supply Hub provides added flexibility in managing short-term gas positions, and, importantly published information on bids and offers, traded prices and volumes.
QGC, p. 5	Introducing additional trading hubs offers a short-term solution, but could split market liquidity (eg at the Wallumbilla GSH) and create greater price volatility. Given the size of the east-coat market, there is significant benefit in concentrating trading/liquidity at one trading point (eg Wallumbilla). An effective short-term capacity trading mechanism (reflecting efficient short-term pricing), would likely enable Southern participants (and those looking to supply the Southern markets) to more cost effectively transact and manage risk using Wallumbilla as a central point. QGC has suggested rather than establish a new pricing point at Moomba, it becomes a new GSH delivery/receipt point and trades are referenced to Wallumbilla.

Stakeholder	Comment
QGC, p. 5	The creation of a “within-day” gas market should be a priority issue, with an extended trading day.
Santos, p. 4	Limited available capacity to transport gas limits arbitrage opportunities between markets.
Santos, p. 5	Supportive of Moomba GSH.
Santos, p. 5	The impact of trading at WGSH should not be a consideration in determining if another hub or delivery point is needed: if there is demand for an additional hub or delivery point and this is executed properly, this will bring in new market participants and give confidence to the whole market, increasing liquidity.
Santos, p. 5	The ability to facilitate 'bespoke' trades through the WGSH is a good functionality.
Stanwell Corporation, pp. 3-4	Liquidity in facilitated markets limited by access to underlying infrastructure. Complexity and cost of facilitated markets are a barrier to entry.
Stanwell Corporation, p. 4-5	Brisbane STTM reduces liquidity at Wallumbilla Gas Supply Hub, as month ahead balancing in the Brisbane STTM prevents trading on a day to day basis at Wallumbilla GSH due to uncertainty over how much to set aside for balancing obligations. Ideally, one market would operate in each region in order to maximise liquidity.
Stanwell Corporation, p. 6.	A Moomba GSH would: • increase liquidity in the market overall; • reduce liquidity at Wallumbilla GSH; and • add complexity to trading between the hubs due to the different start of gas day.
Markets: risk management	
Adelaide Brighton, p. 3	Users being able to manage market deviations through market schedule variations (MSVs) allows risks to be reduced.

Stakeholder	Comment
AGL, p. 3	Experience of the Wallumbilla gas supply hub vindicates the role played by AEMO in removing settlement or counterparty risk often associated with bilateral trades.
Alinta, p. 8	Exposure to additional pipeline charges is unknown at the time of capacity trade and can be difficult to manage.
Alliance of industry associations, p. 7	Within the alliance of industry associations, individual associations support: • the development of financial derivatives as a means for risk management (alternative to physical supply contract). This will need a daily gas price to settle against, which is the role the STTM and the DWGM currently plays; and • consideration of compensation for any businesses that are required to be curtailed if they have a firm gas supply contract and gas transportation agreement in place.
ESAA, p. 1	Supportive of an incremental approach to gas market reform that has regard for existing contracts.
ESAA, p. 5	In the STTM there are a number of complex charges/payments associated with market deviations that cannot be effectively hedged. These include charges/payments relating to: market operator services (MOS); short and long term deviation payments; contingency gas (which has not been required to date); and the settlement surplus or shortfall that is allocated at the end of each month.
ESAA, p. 7	Similar to the STTM, risk in the DWGM is not embedded in a single daily market price. Reducing the complexity of ancillary payments and uplift charges and linking them to the market price could improve participants' ability to assess and manage risk.
EnergyAustralia, pp. 2-3	There is no transparent forward market, limiting participants from effectively managing risk. This is increasingly important given that the domestic gas market will be linked to the international market, requiring the hedging of currency and oil prices risk.
EnergyAustralia, p. 2	Market reform must facilitate price discovery and transparency in spot markets.
ERM Power, pp. 3-5	The recovery of part of the cost of ancillary payments through the allocation of congestion uplift is not on a cost to cause basis and is inequitable. A rule change should be made to enable all uplift costs to be recovered through the existing surprise and common uplift mechanisms.

Stakeholder	Comment
ERM Power, pp. 6-7	There is value in exploring the merits of moving away from the current unconstrained pricing and ancillary payment/uplift cost regime. Congestion uplift fails to allocate costs to their cause. The remaining cost allocation mechanism smears costs across the market. Uplift risk is unhedgeable. LNG can mitigate risk, but this is expensive. A financial market to mitigate risks is precluded by the current arrangements.
ERM Power, pp. 7-8	The maximum market price in the DWGM should be reviewed, with specific consideration to reduce it to a lower level. The higher the market cap the higher the risk faced by retailers.
GDFSAE Australia, p. 2	Market liquidity and the opportunity to manage risks arising through market participation do not match participants' interests. The reasons for this include absence of integration, historical hub by hub developments, markets overly influenced by physical limitations, high entry and transaction costs, and focus on bilateral contracts and contractual strictures.
Lumo Energy, p. 7	A review of the MOS arrangements would be welcomed, as MOS is an inappropriate way to manage deviations. Intraday trading would potentially change the need for MOS, by enabling participants to be better informed of their actual deviations on a gas day.
Lumo Energy, pp. 15-16	A review of the methodology, settings, and the need for increased harmonisation between the STTM and DWGM market parameters is necessary. A recent review undertaken by AEMO suggested that the LNG industry would increase risk for market participants.
Lumo Energy, pp. 16-17	A review investigating the feasibility of making AMDQ and AMDQcc firmer would be appropriate.
Origin Energy, pp. 2-3	Facilitated markets are complex, impacting risk management. The current pricing structure is not truly reflective of market costs in either the STTMs or DWGM. To improve this, market costs should be incorporated into the market price.
Qenos, p. 4	The STTM has been a positive development, providing an alternate means of purchasing gas, and price transparency. However, pricing can be volatile, and long term gas contracts are still required. With five gas producers providing 85% of the gas, there may be significant power over long term gas pricing.
Qenos, p. 5	Financial derivatives would be useful to manage risk.

Stakeholder	Comment
Santos, p. 4	The ability to set a price ceiling in the STTM markets minimises price risk.
Santos, p. 4	Santos would welcome a review of the STTMs for inclusion of an intraday trading service. Under the WGSH, consideration should be given to making intraday trading more cost effective.
Santos, p. 4	STTMs are an effective mechanism for the efficient management of the daily supply and demand imbalances.
Pipelines: capacity trading	
Adelaide Brighton, pp. 4-5	The condition where shipper can purchase all firm capacity on a pipeline and then restrict customer to purchasing from that shipper is not optimal. The shipper gains monopolistic power which it can abuse by forcing customers to purchase both commodity and haulage from one supplier. The alternatives are building a network bypass to gain access to competitive market pricing, or relocation of facility. Such shippers should be required to make available capacity that is not utilised.
AGL, pp. 5-6	"Trade inhibitors" associated with current pipeline contracts and practices are: • The enumeration of delivery points in GTAs and the delays in including an additional delivery point get in the way of shippers being able to offer their capacity to a third party. Delivery points should be grouped into zones to provide shippers flexibility. • The often related requirement to negotiate an allocation agreement with the incumbent shipper at that delivery point. If the pipeliner were to provide the allocation at that delivery point as part of a standard service offering for delivery points, this obstacle can be sidestepped. • Nomination cut-off times in existing GTAs are generally not based on operational requirements. • Services related to forward haulage service are more in the nature of a transaction that would warrant an administrative charge, rather than a volume-driven fee structure. Furthermore, standardising the terms and conditions would keep transaction costs down.

Stakeholder	Comment
	AGL is broadly supportive of reform to enhance capacity trading, but consideration should be given to: • impacts on investment; • the need to accommodate shippers' and retailers' need to offer firm gas to end-users; and • the suitability of overseas models in the Australian context.
Alinta, p. 7	Alinta is of the view that capacity trading in the east coast gas markets is currently less than ideal, driven by information on available capacity in the forward period being limited to select listing services.
Alinta, p. 8	Marginal benefits of increased pipeline trade may be dwarfed by more significant benefits in retail gas markets.
APA, pp. 20-22	APA supports industry led initiatives to develop secondary trading in pipeline capacity. For example, APA and other pipeline owners have recently introduced new services to support additional capacity trading. APA considers its Capacity Trading Service 'addresses an existing barrier to capacity trading, being the administrative complexity and risk of managing shipper nominations, allocations and imbalances on behalf of the counter-party.' Additional measures, such as further improvements to the Bulletin Board and the Energy Council's capacity trading rule change are expected to reduce barriers to capacity trading by improving transparency and lowering search and other transaction costs.
Arrow Energy, p. 6	The full benefits of market developments and enhanced trading arrangements cannot progress without a more effective transportation regime, including capacity trading and access, which encourage efficient market outcomes. The benefits of a single pipeline regulatory regime with clear mechanisms for accessing capacity will enhance investment certainty and facilitate deeper market development. Attaining access to capacity presents a number of challenges that must be addressed: the rights of existing asset owners; the impacts on the risk position and opportunities for asset and capacity owners; the mechanism for providing access; commercial terms; and the benefit to the market.
AEMO, p. 1	Recommends three areas of development to lead to more efficient secondary trading of pipeline capacity:

Stakeholder	Comment
	• incentives for shippers and pipeline owners to make available unused pipeline capacity, particularly on a short-term basis; • mechanisms to support trading of capacity on a short-term basis; and • services from pipeline operators to improve intermediation such as standardised terms, harmonising tariffs, maximising tradable legs of pipeline capacity.
APLNG, p. 2	It is important that current transportation arrangements are honoured. However, APLNG supports the ability to access pipeline capacity not being utilised by the primary holder. Streamlined standard commercial terms based on marginal cost basis would assist in this effort.
APPEA, p. 3	Supports the introduction of a pipeline trading capacity initiative.
APGA	Trading of transmission capacity and commodity gas occurs in the eastern Australian gas market. Additionally, short term capacity is made available to all market participants on a non-discriminatory basis (as available and/or interruptible capacity). APGA does not support the view that eastern Australian pipelines are under-utilised, noting that the annual utilisation rate is 52%, compared to the Midwest (32%) and Northeast (30%) regions of the United States. APGA considers there were two impediments to increased short term capacity trading, both of which have been resolved. The first relates to lack of harmonised contracts and information availability for transfers, which has been resolved through industry and AEMO led processes (bulletin board and standard contracts). The second is the limited number of participants in the markets, where participants with capacity cannot find a willing counter-party at the delivery point. APGA considers this is largely addressed by pipeline owners providing delivery point flexibility to shippers. Any further impediments to trading should be resolved through the COAG Energy Council's rule change proposal to support capacity trading. APGA considers this process, enhanced by the industry-led initiatives, should be given time to work before further changes are contemplated. APGA does not support the introduction of an oversell and buy back mechanism into the eastern Australian gas market.
GDFSAE, p. 6	Easier trade of capacity should be an outcome of the Review.

Stakeholder	Comment
GDFSAE, p. 6	GDFSAE does not see the capacity discussion as a debate between contract and market carriage models. While there are identifiable impediments to capacity trading on contract carriage pipelines, market carriage also creates complexities and it may fail to provide signals for pipeline augmentation.
GDFSAE, p. 6	Given the need to underpin investment it is understandable that pipeline owners and operators are defensive of the contract carriage model. While supporting pipeline investment cannot be overstated it should not mean the existing framework is sacrosanct. While long term contracts are not absolute barriers to capacity trading in all forms they currently inhibit capacity trading.
GDFSAE, pp. 6-8	Any developed approach to capacity trading should take account of existing arrangements and should be used uniformly across Eastern Australia. While voluntary mechanisms have been advanced, experience suggests that governments can play a role in facilitating structures and frameworks that encourage liberalised market outcomes. As an alternative to current arrangements, and models overseas, GDFSAE can conceive of a model which allows incumbent shippers to signal the price at which they would be willing to surrender tranches of capacity, including at times of high usage. Areas for investigation are: • mandated standard contractual terms for short and medium term capacity trades; • addressing prohibitive contract terms; • contractual congestion; • availability of bundled products between hubs; • trading models used elsewhere; • alternative pipeline investment models; and • pipeline obligations to limit market impact.
ESAA, p. 1	A key area includes pursuing enhanced market transparency and contract standardisation in support of industry-led pipeline capacity trading initiatives.

Stakeholder	Comment
ESAA, p. 9	Flexible and transparent access to pipeline capacity is important for the development of a liquid and transparent commodity market. However, the property rights of existing capacity holders should be considered. It is not clear that implementing some form of mandatory trading would deliver the efficiency gains necessary to justify such significant intervention. The 'trade facilitator' model recently developed for the South West Queensland Pipeline, RBP and Queensland Gas Pipeline is an important initiative in this regard. It demonstrates the ability of industry to respond to changing market needs in a targeted and light-handed manner. The COAG Energy Council's agreement to pursue enhancements to information provision and standardisation of contractual terms and conditions for secondary capacity trading is a positive step. It will be important to allow them sufficient time to take effect before additional interventions are considered.
EnergyAustralia, p. 2	Gas transportation is dominated by opaque and bespoke contract carriage arrangements. The market carriage model in Victoria is the exception, but it is complex and interfaces poorly with other pipelines.
EnergyAustralia, p. 3	For the contract carriage model, holders of existing capacity have strong commercial incentives to trade capacity, and reform should focus on removing barriers to mutually beneficial trade: • standardisation of contracts; • simplified processes to change delivery points; and • reduced search and transaction costs for short term trades.
Epic Energy, pp. 1-3	Contract carriage supports capacity trading, as the contracted terms allow participants to negotiate a price that reflects a reasonable allocation of risk between the contracting parties. Further, secondary trading of pipeline capacity already occurs and the benefits of further reform are likely to be limited. However, if a formal secondary trading arrangement is put in place, it must preserve the value of the primary capacity market. Epic also noted that there is data to suggest that Australian capacity utilisation rates are higher than utilisation rates in North America and Europe.
ERM Power, p. 11	Supports recent developments to facilitate capacity trading. Considers it may be worthwhile revisiting the concept of a voluntary capacity trading platform. This may include considering how spare capacity may be released for use.

Stakeholder	Comment
GLECMU, pp. 2-3	Improving the efficient access and use of pipeline and gas infrastructure is a fundamental component of the gas market. The full benefits of market developments and enhanced trading arrangements require a more effective transportation regime, including capacity trading and access, which encourage efficient market outcomes. Consideration should be given to all market-based options that facilitate greater access to capacity. The preferred mechanism for realising shared use should provide clear signals to commercially incentivise owners to facilitate access.
Jemena, pp. 1-2	Following extensive consultation, the industry is implementing measures to encourage more efficient usage decisions on secondary pipeline capacity trading.
Lumo Energy, p. 18	Lumo is supportive of the current process for improving information provision to facilitate capacity trading.
MEU, p. 4	Information asymmetry is a major barrier to efficient trading, and requires more than enhancements to the Bulletin Board to be rectified.
MEU, pp. 7-8	Hoarding pipeline capacity is a problem in STTMs and pipelines outside the STTMs. Interruptible capacity is offered at a higher cost than firm capacity or not offered at all. It is not clear that better mechanisms to trade capacity will result in more capacity being released.
Origin Energy, p. 4	The AEMC should, in the first instance, investigate and articulate the current issues with capacity trading, and their materiality. Such a review should also consider the range of services available.
Origin Energy, pp. 4-6	Market arrangements are sufficiently flexible and incentives exist for shippers to provide capacity to the market if demand exists. A guiding principle for any proposed change should be that there is no diminishing of property rights for existing capacity holders. Origin considers there may be merit in a multi-pipeline voluntary trading platform but cautions against any more interventionist market design changes in the first instance. Origin considers this approach is the most cost-effective way to encourage capacity trading that preserves existing capacity rights and will not adversely impact future investment. A working group of all relevant stakeholders be established to fully develop and cost this proposal.

Stakeholder	Comment
Origin Energy, pp. 7-8	Were regulatory intervention required (which Origin considers would only be in the case that other, non-regulatory intermediate steps were implemented and proven to be unsuccessful), Origin considers that caution be applied to the appropriateness of overseas experience to the Australian context, and consideration be given to: • a shipper's flexibility to respond to changing supply and demand patterns; • impact on investment; • the entry-exit system; and • transmission system operator estimation of capacity and use.
QGC, pp. 2-3	Short-term capacity trading arrangements are essential to develop market liquidity, reduce price divergence and facilitate the development of the futures and forward markets. Addressing this issue is central to “opening-up” the market and enabling gas to be directed towards participants who value it most at any given time. Current impediments to short-term trading in capacity include: • potential lack of market awareness by shippers holding capacity; • transaction costs potentially exceed value of sale; • holding capacity maintains flexibility and avoids nomination complexities; • potential commercial opportunities: managing capacity may create price differences; and • contractual clauses which preclude trade.
QGC, pp. 3-4	An oversell and buy-back mechanism (akin to that used in the European market) could be introduced. To do so, the AEMC should consider the operational and risk management measures for pipelines and the structure of existing contracts. Encourages the AEMC to consider this matter further.
Santos, pp. 1, 7	The main impediment in the current facilitated markets is the lack of a firm transport availability to get gas to and from different trading markets. The current options to trade capacity are good for large players, although they may not meet the future vision of an actively traded market between locations and arbitrage trading opportunities.

Stakeholder	Comment
	A standardised market for available capacity should be introduced, with reduced transaction costs. Also, current pipeline owner administrative costs are too high for new traders.
Stanwell Corporation, p. 3	An active capacity trading market is unlikely to occur without changes to existing access arrangements and regulatory arrangements for nodal points. Capacity holders can reserve capacity with little or no incentive to release it, reducing available capacity for smaller and new entrant users.
Stanwell Corporation, p. 3	Pipeline arrangements can restrict competition. For example, excessive fees are charged on intraday nominations, preventing users from purchasing unused capacity from other parties. Instead, users are encouraged to purchase services from the pipeliner.
Stanwell Corporation, p. 7	Other impediments to capacity trading include: • non standard contracts; • onerous set up process; • point to point GTAs; • inadequate information on available capacity; and • significant variance charges on capacity trades.
Stanwell Corporation, p. 6	Trading mechanisms and regulatory changes to incentivise pipelines to support such a market should facilitate capacity trading.
Pipelines: investment	
APA, pp. 14-16	APA considers that the current arrangements provide a supportive and appropriate regulatory environment that provides for efficient investment in most pipelines (except the DTS).

Stakeholder	Comment
	The regulatory arrangements in the DTS are undermining efficient and timely investment in the DWGM, particularly now that AMDQCC has been determined to be a reference service with an associated regulated tariff applied. APA considers the result of this decision is that it no longer has certainty of throughput or revenue from allocation of AMDQCC, therefore undermining the original intent of AMDQCC. APA is also concerned about the opportunity for free-rider participants to benefit from investment in infrastructure in the DTS as a result of the 'socialisation' of investment under the market carriage model in Victoria.
Australian Energy Regulator, pp. 3-4	There is evidence that the provisions in the NGR (and its predecessor, the Gas Code) enable timely investment in the DTS regardless of its timing within a regulatory period.
APPEA, p. 2	The APPEA recognises the importance that bilateral contracts have played in underpinning market development on the east coast.
APGA	Since 2000, APGA's members have invested in and built over $2.2 billion of new infrastructure providing 4000km of coverage across 10 new gas transmission pipelines. Since 2010, APGA members have invested over $850 million to expand existing infrastructure. These investments have been facilitated through bilateral negotiations and contracts. Further investment will be required to meet the needs of participants in the future. There has been a move towards short-tenure contracts to underpin infrastructure investment recently. For example, APA has announced a capacity expansion for transportation services between Victorian and NSW at a cost of $160 million for three shippers for contracts of between four and six years, compared to historical contract lengths of over 10 years. As a result, the pipeline owner is bearing more risk associated with recontracting for this investment. In relation to the DTS, APGA are concerned that the regulatory arrangements in place prevent investment from occurring in a timely manner. Delays in investment caused by regulation have implications for efficiency and market welfare. In contrast, pipelines that are fully covered and tariff-regulated under contract carriage have less difficulty investing outside the regulatory cycle as they can offer firm capacity rights. There are significant costs associated with market carriage and access regulation as a result of delays in investment.
BHP Billiton, p. 3	The role of gas storage facilities in supporting fully functioning gas markets is important, particularly in the context of highly seasonal demand. The eastern Australian gas market is at the early stage of gas storage development.
ESAA, p. 7	Investment decisions in the DTS are driven by the regulatory process, which may be less efficient and timely than relying on

Stakeholder	Comment
	market driven investment decisions.
ESAA, p. 8	Significant investment in pipeline capacity has occurred, with the current framework providing a reasonable balance of end-user protection with service provider protection and incentives.
ESAA, p. 8	Tariff uncertainty due to prospective near-term regulatory reviews creates significant risk for both pipeline operators and financiers. As such, the light handed or no coverage options are seen to be important features of the regulatory environment. While the no-coverage option may create some potential negatives from the perspective of third parties, it is not clear that it creates a fundamental constraint to the development of the industry.
EnergyAustralia, p. 4	For the market carriage model, the review should focus on ensuring efficient and timely investment in new capacity and improving participants' ability to manage risk.
Epic Energy, p. 2	Timely and efficient investment occurs in response to market demand on contract carriage pipelines.
ERM Power, p. 6	Lack of firm capacity rights in the DWGM reduces incentives for market-led investment in pipeline capacity expansions. This can lead to a lack of transmission capacity, with expansions not occurring in a timely manner, or at all. Optimisation of investments and daily operations is not enabled. Options to introduce market-led investment and make investments more efficient should be investigated. This should not build on the current uplift/AMDQ mechanism, which does not provide effective price signalling. New investments may be able to be contracted for, providing firm capacity rights for participants.
Jemena, pp. 2-3, 7	The market currently provides incentives for the efficient use of and investment in pipeline services and Jemena has invested $450 million in new capacity since 2007. Any policy or regulatory response to encourage efficient utilisation of and investment in pipeline infrastructure must be: • proportionate and recognise pipelines account for around 5% of a typical residential customer's gas bill in NSW; • developed with a clear understanding of the problem with current arrangements, as well as the costs and benefits of any proposed response; and • guided by the long term interest of customers.
Lumo Energy, pp. 12-13	Investment in the DTS is occurring in an efficient and timely manner. There is a lack of evidence that investment has not been timely or efficient.

Stakeholder	Comment
MEU, p. 3	Investment required in transmission capacity at critical points in the system to better facilitate bi-directional gas flows, storage, swaps, and liquidity.
MEU, pp. 9-10	If insufficient capacity exists on a contract carriage pipeline, participants seeking access must fund new investments, which may provide a financial barrier to their entry. Market carriage pipelines allow new investment to occur with costs for increased capacity socialised so all shippers pay the same rates for the same service. The claim that the DWGM does not provide sufficient investment signals needs to be rigorously assessed. AEMO provides an independent mechanism for assessing investment in the transmission planning role. While there may be opportunities to improve this, it is not clear that this arrangement warrants a major restructure.
Manufacturing Australia, p. 7	The Federal Government should designate gas pipelines as assets of national importance as a key step to ensure equality of access.
Manufacturing Australia, p. 7	The COAG should map and develop a network of pipelines to bring Australia's stranded gas assets to market and connect the Northern Territory and Eastern gas markets.
Manufacturing Australia, p. 7	Federal and State governments should identify strategic "energy corridors": regions or zones that are crucial to future energy needs, either for resource extraction, pipelines of other infrastructure.
Santos, p. 6	Five year determination cycle can delay investment in the DTS.
Santos, p. 7	The low number of uncovered pipelines is not a concern in its own right. Investment, where there is demand, has been forthcoming, showing the market is working efficiently.
Stanwell Corporation, p. 2	Transmission pipeline investment and revenue should be regulated by the AER under a NEM-style carriage model operated by AEMO.
Stanwell Corporation, p. 3	Current regulatory arrangements seem to reward pipelines for constraints rather than encouraging investment.
Pipelines: trading between jurisdictions	

Stakeholder	Comment
Adelaide Brighton, p. 4	It is difficult to move gas from Victoria to adjoining regions. Consistent regulatory framework may assist in ability to move gas from one region to another.
AGL, p. 5	Given the increasing interconnectedness of pipelines, it would be appropriate to further review the interface between Victoria's market carriage regime with contract carriage regimes in SA and NSW.
AGL, p. 7	The interaction between the market carriage and contract carriage models is an appropriate consideration for this review. However, AGL does not endorse a review of the merits of market carriage versus contract carriage options.
Alinta, p. 6	Getting gas into the hub precedes any opportunity for the hub to work as a viable market overall and for individual trades to occur. Unless all participants at the hub can guarantee delivery, trade will be always to a degree remain constrained.
APA, p. 15	APA considers the application of system security requirements under the NGR is inconsistent with the NGO, in that there is a bias towards Victorian system security at the expense of gas flows to other jurisdictions, particularly New South Wales.
APA, pp. 25-27	APA considers that the current access regime provides a supportive and appropriate regulatory environment that provides for efficient investment in most pipelines (except the DTS). Nevertheless, APA has raised concerns about the following aspects of the regime: • redundant assets provision; • speculative capital expenditure account; and • gaps in the operation of the tariff variation mechanism.
BHP Billiton, p. 2	There is an opportunity for Australian energy regulators to consider a more uniform approach to gas pipeline regulation in a manner similar to that which applies in other markets such as the UK and the United States.
EnergyAustralia, p. 2	Reform should focus on encouraging trade between locations.
EnergyAustralia, p. 4	The review should focus on the interaction between the Victorian system and contract carriage pipelines.

Stakeholder	Comment
Jemena, p. 6	Jemena does not consider that differences in market and contract carriage arrangements across eastern Australia represent a material issue. Any proposal to overhaul existing arrangements must have regard to existing property rights, as well as the costs, benefits and risks of alternative arrangements for participants, as well as end consumers. Jemena considers there is scope for harmonising market parameters, such as the alignment of gas days.
MEU, p. 5	AMDQ is allocated to retailers rather than consumers, limiting the ability of consumers to switch retailer.
MEU, p. 6	Export arrangements between market hubs should be a focus of the review. Investment in transport within the DWGM to provide increased export can be addressed with the beneficiaries of increased capacity paying for in-region capacity that is required to enable additional gas for export from Victoria.
Origin Energy, p. 3	Exports from the DTS should be considered equal to DTS demand as this supports the principle that gas should flow to the highest value use.
Santos, p. 6	Constraints are a daily occurrence out of the DTS.
Stanwell Corporation, p. 4	Supports the integration of the east coast gas market, and suggests a NEM-style market operated by AEMO.
Pipelines: third party access arrangements	
APGA	At the time of establishment, the Victorian gas market was essentially an isolated market with significant excess capacity. There has been significant change in the market since then, with the construction of the Tasmanian Gas Pipeline, SEA Gas Pipeline and Eastern Gas Pipeline, as well as the construction and expansion of the Victorian Northern Interconnect. Historic issues that inhibited the transportation of gas from the DWGM to contract carriage pipelines have largely been resolved through an AEMO procedure change (matching allocated AMDQCC to firm capacity rights at withdrawal points).
APGA	Transmission pipelines have an important role in developing liquid, transparent and competitive wholesale markets, however further regulation is not the 'silver bullet' to further development of the markets. The current access regimes in the Gas Code and NGL have applied alongside significant investment that has promoted competition between gas supply basins. As interconnection between the pipelines increases, pipelines must remain

Stakeholder	Comment
	competitive as alternative sources of supply and transportation become available to shippers. In relation to the DTS, APGA is concerned that the regulatory arrangements in place prevent investment from occurring in a timely manner. Delays in investment caused by regulation have implications for efficiency and market welfare. In contrast, pipelines that are fully covered and tariff-regulated under contract carriage have less difficulty investing outside the regulatory cycle as they can offer firm capacity rights.
EnergyAustralia, p. 2	Reform should focus on encouraging trade in pipeline capacity.
Epic Energy, pp. 2-4	Contract carriage arrangements enable pipeline owners and shippers to negotiate bespoke contracts that best reflect the variability in supply and demand in major demand centres. Contract carriage also supports and encourages timely investment in pipelines.
Jemena, pp. 3-4	Contract carriage arrangements have allowed Jemena to provide innovative services to meet the needs of their customers, including: allowing shippers to change their delivery and receipt points, and storage products to allow intra-day nominations. Jemena maintains non-discriminatory access policies for both the EGP and QCP, which mean that available capacity is advertised on the Jemena website and all shippers have equal access to it.
MEU, p. 3	Impediments to access to pipelines and capacity trading exist and, therefore, the framework is not delivering efficient outcomes.
MEU, p. 7	A number of pipelines are monopolies but are uncovered. Several regional industries and cities are provided gas from a single, unregulated pipeline. The regime to allow for these pipelines to be covered is inadequate for these purposes; the criteria to gain coverage create a major hurdle to any party seeking coverage.
Manufacturing Australia, p. 6	The objective of market reforms should include access to infrastructure to enable producers to bring their product to market.
Stanwell Corporation, pp. 3, 7	Access arrangements are inadequate as capacity holders are not incentivised to release spare capacity. As available is inadequate for many participants.
Information accessibility	

Stakeholder	Comment
Alinta, pp. 3-4	As a general measure, the level of transparency [in relation to the LNG] market should be at least equivalent to the National Electricity Market (NEM) and in the spirit of disclosure obligations for the Australian Stock Exchange. In Alinta's view there are significant benefits to all parties at some level through increased information disclosure and the removal of information asymmetries. Given the clear connection between gas production, gas prices and electricity generation, there is a compelling argument that a similar compulsory reporting obligation to the NEM should be required for upstream gas producers with respect to any medium term changes in the capacity of their production facilities. The existing Gas Bulletin Board requirements in Western Australia could be used as a model for the east coast.
Alinta, p. 4	The current short-term capacity outlook information has been effective in informing participant decision-making. There is, however, further scope for enhancement. Consideration should be given to: • linepack data, provided by relevant zones, at the beginning and end of day; and • intra-day data on capacity, flow and linepack.
Alinta, p. 7	Alinta would encourage the review to consider steps to increase information from whom capacity is available from.
Alliance of industry associations, pp. 6-7, 13	Gas market solutions must reflect the full range of identified market-based reforms for the gas market, including disclosure of available capacity at all stages of the gas value-chain. There should be improved planning and transparency mechanisms such as the Gas Statement of Opportunities and Bulletin Board, and continuing reforms to publish available transmission pipeline capacity and accelerating efforts to develop a published gas price index.
Alliance of industry associations, p. 7	Within the alliance, individual associations support: • the introduction of an Independent Gas Commissioner in each state to oversee gas field development much like has been established in Queensland. This would provide a trusted, independent source of information on gas fields and their environmental performance; • the provision of fact-based information and education to assist all stakeholders to understand the sources and use of gas throughout the economy. This could include the ongoing sourcing of gas from hydraulic fracturing methods over

Stakeholder	Comment
	significant amounts of time in East Coast markets; and • increased transparency for the dealings between gas pipelines and gas shippers, so that gas users are best placed to understand ahead of time how the market is functioning.
Argus Media, pp. 3-4	Price transparency can best be promoted by encouraging independent media organisations such as energy Price Reporting Agencies to produce price assessments that most accurately reflect the supply and demand fundamentals of a freely operating, non-price regulated market. The AWX – the Argus Wallumbilla Index – provides a weekly price reference for gas traded at Wallumbilla for delivery on a month ahead basis, and this is an example of such a product. Price Reporting Agencies should be recognised for their role in bringing transparency to otherwise opaque markets, and they should be left to function without government interference, oversight or regulation. Government can play a role in enhancing price transparency by encouraging market participants to report comprehensive transactional and market information to Price Reporting Agencies, avoiding the adoption of legislation that might deter the flow of information or Price Reporting Agencies, and adopting independent price assessment for tax reference purposes.
Arrow Energy, p .5	In the absence of prohibitive costs and breaches of confidentiality, Arrow supports improvements in information availability, transparency and discovery for the purpose of facilitating trade and liquidity, and providing clear price signals. Aspects of data provision that should be considered in identifying the most appropriate data set include: accuracy of data (noting physical constraints), frequency of data, aggregation of data, timing of data release (daily, hourly or real time), the cost and timeframe required to establish measurement infrastructure to provide data.
Arrow, Energy, p. 9	Arrow believes that information currently being provided by the Wallumbilla hub, combined with work being undertaken by AEMO and the industry, will meet participants’ needs.
AEMO, p. 2	There may be value in improving the Bulletin Board to provide more relevant and dynamic information (eg, real time data and information about storage).
Australian Energy Regulator, p. 3	As the market matures, the AER would propose reporting more measures on the Bulletin Board and at the GSH.
Australian Pacific LNG, p. 1	Supports the increased sharing of information and continued development of the Bulletin Board with regards to: real time information of volumes; pipeline utilisation rates; posting of available capacity; and establishing a central data resource.
APGA	There are opportunities to enhance existing information available on the Bulletin Board. In particular, APGA considers the

Stakeholder	Comment
	publication of two existing AEMO data sets would provide additional transparency and assist capacity trading: • a graphical representation of historical daily flow data against pipeline capacity (implemented in Bulletin Board redesign in December 2014); and • analysis of historical flow data on each day of the year. Further, APGA considers the Bulletin Board should publish available firm capacity by pipeline each month, with a 12 month forecast to give the market a 'clear indication of current and future available capacity.' Additional information on the export and production capability, particularly in relation to the LNG facilities at Gladstone is critical to market participants' decision making.
GDFSAE, pp. 4-5	Presently, information arrangements are fragmented across multiple platforms and are incomplete. In general terms, efficiency will be maximised by appropriate information disclosure to enable transparent price discovery, true incentives to be revealed and risks to be borne by the most appropriate parties. This suggests a level of transparency at least equivalent to the National Electricity Market and in the spirit of disclosure obligations for the Australian Stock Exchange. GDFSAE believes the review should consider information on the use of linepack, flow and nominations, medium term system adequacy, contracted capacity, injections and withdrawals and upstream supply. Areas for investigation are: • information adequacy; • use of existing systems; • roles of contracts in accessing data; • producer data; • gas demand data;

Stakeholder	Comment
	• capacity and adequacy data; • load profile data by gas network area; • ‘real time’ feeds; and • short term information.
GLECMU, p. 2	In the absence of prohibitive costs, the GLECMU supports improvements in information availability, transparency and discovery for the purpose of facilitating trade and liquidity, and providing clear price signals.
ESAA, p. 10	The ESAA is supportive of efforts that increase the availability of gas market information. Areas for exploration include: • Enhanced firm/non-firm pipeline capacity and flow data. • Enhanced operational pipeline capacity information. However, it is premature to consider alternative arrangements relating to the provision of medium and short-term capacity information until these recent changes have been given sufficient time to take effect. • Information relating to relevant facilities and large users. • Beginning-of-day linepack. The ESAA does not believe it is appropriate to enforce mandatory reporting of secondary capacity trades that occur off market.
EnergyAustralia, p. 2	Market reform must improve the accuracy, timeliness and transparency of market information about physical supply and demand. This is a potential priority for phase 1 of the Commission's review.
ERM Power, pp. 11-12	A deficiency is present in the lack of publicly available information relating to the LNG industry. The Bulletin Board should be amended to reflect the establishment of an LNG/Gladstone demand zone, thereby capturing LNG pipeline flows (historical and forecast) and capacity outlooks/outage information related to LNG facilities.

Stakeholder	Comment
Jemena, p. 2, 3-4	Jemena recognises the importance of the price of transportation services being appropriately transparent to encourage efficient utilisation of the network. However, Jemena considers any policy or regulatory intervention must address a clearly defined market failure in relation to transparency in the pipeline sector and consider the current market, regulatory and contractual arrangements. Jemena supports the APGA low cost proposal for improvements to the Bulletin Board to assist secondary trading without compromising confidentiality.
Lumo Energy, p. 8	STTM prices do provide a price that reflects the underlying supply and demand conditions in the market.
Lumo Energy, p. 11	Wallumbilla GSH provides very useful information to market participants.
MEU, pp. 4-5	Facilitated markets do not reflect market fundamentals, and forecasts for gas availability, capacity and price are either unavailable or inadequate. This impedes gas trade and risk management.
Manufacturing Australia, pp. 5, 6	The objective of market reforms should include daily publication of accurate and credible gas supply availability and price. AEMO should require: • gas producers to report and regularly update the market on proven and probable gas reserves; • pipeline transport pricing to be published based off a published benchmark price for the injection and withdrawal points; and • open access via electronic markets provided to all market participants. Participants requiring shipping can price and book transport off the electronic market.
Qenos, p. 2	Facilitated market prices should be included on the Bulletin Board. This is part of a broader recommendation to centralise information in one location to improve ease of contracting.
QGC, p. 6	As part of this Review, the AEMC should also identify any relevant changes to east coast gas market information reporting that are necessary to support the overall successful delivery of any of its key recommendations.

Stakeholder	Comment
Santos, p. 4	Increased transparency of price and gas volume schedule would improve efficiency.
Santos, p. 5	The information provided for the GSH is satisfactory. Santos has been encouraged with the addition of moving to a single product.
Santos, p. 8	The information on capacity utilisation provided on the gas bulletin board is adequate for current purposes.
Stanwell Corporation, pp. 7-8	Supports current work on redevelopment of Bulletin Board. Bulletin Board contains incomplete and untimely information. Information that would assist in participant decision making includes: • 12 month forecast of capacity, system adequacy and maintenance information; • intraday pipeline flows and linepack for all pipelines, not just regulated ones; • capacity and amount of available gas at storage facilities in Queensland, including non-designated facilities; • forecast and current amount of pipeline capacity available for storage; and • net system load profile for each demand hub.
Other	
Alinta, p. 9	Alinta encourages further consideration of a coordinated approach to system security that still retains control at the jurisdictional level but results in AEMO acting as the agent in charge of managing technical operations.
Alliance of industry associations, pp. 6, 8	The AEMC should acknowledge the full nature of energy use in Australia, the needs of energy users for an efficient, competitive market, and the full economic and environmental opportunities that are linked to the outcomes in the gas market.
Alliance of industry associations, pp. 7, 9-10	The AEMC should identify the critical evidence gap relating to the current and potential use of gas throughout the manufacturing sector and its supply chains.

Stakeholder	Comment
Alliance of industry associations, p. 10	Consideration should be given to introducing a transitional mechanism that requires all stages of the gas value chain that have capacity available to provide an offer to the domestic market. This obligation should be underpinned by improved disclosure of capacity at all stages of the gas value chain.
Alliance of industry associations, p. 11	The alliance recommends a review is undertaken by the ACCC to assess the depth, liquidity and competitiveness of the Australian domestic gas market.
Arrow Energy, p. 3	Elements of market design that should be considered include: physical market security and stability, supply security, supply competition, provision of appropriate information, access to transportation capacity, supply and demand needs (risk and price), and price transparency.
Arrow Energy, p. 4	The reforms required to deliver an integrated and efficient market are likely to be significant and wide ranging. An ad hoc or fragmented approach to the development of the market is likely to fail.
GDFSAE, p. 3	System security and security of supply are fundamental drivers of aspects of gas regulation and gas hub design, at times to the detriment of market development.
GDFSAE, pp. 3-4	While GDFSAE supports market led reform as a general principle, it is appreciated that facilitating timely development, especially in the face of significant challenges, is likely to require government and industry to take coordinated action. Areas for investigation are: • the role of industry and government; • consultation process and transition; • maintaining a focus on gas markets at a policy level on an ongoing basis to the same extent as occurs with electricity; and • rule change process consistency.
GLECMU, p. 2	Sufficient time for change needs to be considered in any decision making process, including appropriate consultation and transitional arrangements, particularly where major change is being proposed. Although the overall objective of policy should be to promote efficient markets, no participant should be materially disadvantaged by unexpected major changes.

Stakeholder	Comment
Lumo Energy, p. 17	The rule that prevents anyone other than the Victorian Government and AEMO from submitting a DWGM rule change to the AEMC should be amended to be consistent with arrangements in the STTM. Rule change processes are too lengthy.
Manufacturing Australia	Recent changes have rendered the domestic market, dominated by historical structures and regulations, unworkable for demand side participants.
Santos, pp. 7-8	To achieve COAG's vision for gas, there needs to be a greater integration between the markets and pipelines.

Table H.2 Stage 1 Draft Report: submission summaries

Stakeholder	Comment
Stage 1 recommendation: improving price transparency	
MEU, p. 2.	The MEU supports the shorter-term measures aimed at improving price transparency for the reasons provided in the draft report.
Stanwell, p. 3.	Stanwell does not support the use of a survey-based gas price index, noting that the market is too illiquid and bespoke to generate a meaningful benchmark. Stanwell also does not support government aggregating existing publically available information as a "free" service, as it risks crowding out private providers.
SA Water, p. 2.	SA Water supports improvements to long-term price transparency and continuation of the price transparency provided in the STTM.
CQ Partners, p. 7.	CQ Partners considers that the results of any survey gas price index would be almost meaningless without mandatory disclosure of confidential information on prices. CQ Partners also states that with a very limited number of gas suppliers, the results would be open to manipulation and could not be relied upon.

Stakeholder	Comment
ESAA, p. 3.	The ESAA supports increased gas price transparency, as long as there is no mandatory requirement to report confidential GSA prices.
APPEA, p. 10.	APPEA notes that the private sector is already developing survey-based gas price indices, as well as aggregating existing publicly available information and anecdotal reports on gas prices.
AEMO, p. 2.	AEMO notes its previous recommendation to include relevant price information from the STTM and DWGM on the BB.
AEMO, p. 3.	For a survey-based gas price index to be of value to market participants, reported information must relate to a standard trading product, and transactions must be reported in a timely manner. AEMO has established the Wallumbilla Benchmark Price based on day-ahead trading at the Gas Supply Hub. It is the reference price for the ASX Wallumbilla gas futures contracts. Private market reporting organisations survey market participants and publish data on a regular basis eg Argus Media currently publish an index based on participant surveys.
AGL, p. 2.	There is no apparent downside to aggregating publicly available information, and it may be useful for less well-resourced participants. AGL does not support the introduction of a survey-based gas price index, as a price index should develop naturally through enhanced liquidity.
APA, p. 22.	Options to improve price transparency should focus on the operation of markets and the development of price indices.
Jemena, p. 2.	A survey-based gas price index may be likely to provide market participants with a more complete set of data, but there may be challenges in compiling and reporting this information. There should be no mandatory requirement to report confidential GSA prices.
Santos, p. 3.	Santos does not consider that a survey-based gas price index would be a practical or useful tool. Santos supports the aggregation of existing information into one place.
Origin Energy, p. 2.	Origin offers supports for a survey-based gas price index, but considers that there is much detail to work through. Its effectiveness will be dependent on the participation of the market participants, and it is important that there is industry involvement in the development of the index.

Stakeholder	Comment
Origin Energy, p. 2.	Origin supports this recommendation, noting that it could incorporated into the AER's Weekly Gas Market Report, which already provides average prices for the facilitated markets.
EnergyAustralia, p. 3.	EnergyAustralia notes that a new price survey or aggregation of existing public information is unlikely to make a material difference and neither can substitute for robust market trade data.
GDFSAE, pp. 2-3.	GDFSAE is not opposed to a survey-based gas price index, but notes that prices should accurately reflect current supply and demand conditions. The AEMC should be careful not to undermine the private price index providers that exist in the market. The AEMC should initiate a scoping study to identify relevant and meaningful market data to facilitate short-term trade in gas and pipeline capacity.
QGC, p. 3.	QGC is unclear of the value of publishing an additional price index, as Argus Media currently reports a Wallumbilla Hub index and AEMO publishes end-of-day benchmark price for Wallumbilla. Further, aggregating information into one place will only have a minor effect on overall market efficiency and trading. The Stage 1 report should focus on identifying relevant and meaningful market data to assist and facilitate short-term trade in gas and capacity.
Energy Users Association of Australia, pp. 2-3.	The EUAA supports a survey-based gas price index, but provided the inputs are such that an accurate price will be created. EUAA's members differ in their support for either a survey-based gas price index or information aggregation. Currently, prices reported by AEMO do not reflect prices paid by market participants in the bilateral market.
Qenos, p. 2.	Qenos considers that a survey-based gas price index and/or aggregating existing publicly available information would be of limited value. Qenos state that a price index is only of benefit if you can purchase gas at the indexed price.
Visy, p. 4.	Visy does not see value in a survey-based gas price index. Such an index may see participants reveal information that is in their own interests, or not reveal information where it may adversely affect their commercial interests. Visy notes that the DWGM and STTM reveal prices that are the product of daily trading which have generally converged with contract prices over time.
Stage 1 recommendation: information gaps and Bulletin Board "one-stop shop"	
MEU, p. 2.	The MEU supports establishing the Bulletin Board as a "one-stop shop" for all gas market data and assessing the degree to which additional informational gaps fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change.

Stakeholder	Comment
Alinta, p. 2.	Alinta considers that improving the quality of information provided on the Bulletin Board is a worthwhile objective.
Stanwell, p. 4.	Stanwell supports the changes in order to make the Bulletin Board a more comprehensive source of information, and improve the useability, functionality and the reliability of the information provided. Stanwell suggests that the first step is to ensure that all important facilities are registered (including all pipelines, production and storage facilities).
Australian Paper, pp. 3-4.	Australian Paper considers that a "one stop shop" may not be the most efficient option. The AEMC should consider options for the provision of market information that are driven by a cost-effective solution.
CQ Partners, pp. 7-8.	CQ Partners supports gas market data being readily available to all but notes that there may be significant development costs required to redirect all gas market data to the Bulletin Board. CQ Partners considers that Stage 2 should consider the costs and benefits of centralising all gas market data.
ESAA, p. 3.	The ESAA agrees there is merit in consolidating available east coast gas market information for inclusion on the Bulletin Board.
APPEA, pp. 6-10.	APPEA suggests that there is enough information available to allow supply contracts to be concluded between willing buyers and sellers. APPEA supports the AEMC's rejection of calls to require contracting parties to reveal the prices they are required to pay under their GSAs.
AEMO, p. 2.	AEMO favours the AEMC establishing a vision for the development of the BB, consistent with the COAG Energy Council's Vision. Work should focus on developing the BB as a tool with which to support short- and long-term decision-making in gas markets through improved transparency and availability of gas market information. There is also a need to improve the coverage of information required to support risk management in the wholesale market. AEMO hopes that the review will present an opportunity for a thorough review of the BB rules (Part 18 of the NGR). AEMO supports the inclusion of planning and longer-term forecasting information on the BB.
AGL, p. 2.	AGL supports initiatives to develop the BB as a one-stop-shop, and suggests that the AEMC develop long-term objectives consistent with the COAG Energy Council's Vision.
APA, pp. 18-25.	To better reflect the production, flow and consumption of gas amidst a changing market, APA recommends that a number of changes be made to the BB: changes to demand zone definitions, the representation of pipeline storage and changes in linepack, the establishment of a new 'transit' zone, and the publication of schematics showing the pipeline receipt and delivery points that are included in each zone.

Stakeholder	Comment
	Issues relating to accuracy of the information on the BB stem from the ability of the current definitions and structure of the BB to accurately represent pipeline flows, and not from the regulatory and compliance regime. APA supports the publication of long-term planning reports on the BB, with potential for further alignment between the BB and the long-term planning documents prepared by AEMO, so that users of the BB can derive clear long-term forecasts for particular BB zones. APA cautions against the publication of pipeline and storage charges in the primary market. APA considers that the BB could provide links to the relevant tariffs published by the pipeline operator, on a voluntary basis, except as required under the access regime. Linepack data is not required by market participants. Medium-term capacity outlooks have recently been examined, with a rule change coming into effect in January 2015. Therefore, this should not be re-examined at this time. APA considers that within day incident reporting could be better presented on the BB.
Jemena, p. 2.	Jemena is broadly supportive of the centralisation of information, including placing information regarding bids and offers on Jemena's capacity listing page on the BB.
APGA, pp. 4-5.	APGA considers that further reviewing medium-term capacity information should not take place, as the changes need time to be enacted and their effects gauged.
Energy Users Association of Australia, p. 3.	The EUAA is supportive of a "one-stop shop", provided that there: is no duplication; efficient cost allocation to ensure that the administration costs are not passed on into the market; and a complete picture of the gas market (including uncovered pipelines and major laterals to ensure all gas transported in the east coast system is included).
Santos, pp. 3-4.	Santos is supportive of further efforts to aggregate existing market data or improve functionality. In terms of including storage in the BB, Santos notes that not all storage facilities are the same, and that not all storage facilities represent an injection point into a pipeline.
Origin Energy, pp. 2-3.	Origin supports making the BB a "one-stop shop", including: adding prices from the facilitated markets on a new facilitated markets pricing page; planning and longer term forecasts on a new long-term forecast and planning page; expanding the scope of capacity listing to include a voluntary listing service for gas; transportation and storage capacity; and combining the APA and Jemena capacity trading sites into a single site. Functionality should be improved, and greater focus should be given to BB compliance and enforcement processes undertaken by AER and AEMO, as the existing information is not always complete, accurate or timely.

Stakeholder	Comment
AGL, p. 2.	AGL supports initiatives to further develop the BB as a "one-stop shop", where there is a net benefit. AGL suggests AEMC develop a long-term objective for the BB, consistent with the COAG Energy Council's Vision. Functionality improvements should be pursued if the benefits are material.
EnergyAustralia, p. 8.	Real time data is necessary to support the new direction of the market and aids decision-making in emergencies and on high demand days. Providing data on large users and reserves will enable shippers to make better decisions. Measures to improve the accuracy and timeliness of information are supported. All production and storage facilities should be treated equitably under the NGR.
GDFSAE, pp. 3-4.	GDFSAE supports improved accessibility of existing information. It recommends the AEMC undertake a scoping study to determine the relevant information that would facilitate short-term trade of gas and capacity. Specific consideration should be given to: • provision of real time information; • appropriate incorporation of LNG data,; • the COAG Energy Council rule change request; • costs and regulatory burden on business; • appropriate reporting platform and central repositories; and • arrangements operating in overseas markets. GDFSAE is conscious of the issue of the cost associated with providing information, and therefore supports a holistic approach to improving information provision. This includes recommendations on the use of linepack data, storage facilities, and medium term capacity outlooks for facilities including large users, and moves to include "live" data.
QGC, p. 3.	QGC recommends a scoping study be undertaken to identify relevant and meaningful market data to facilitate short-term trading in gas and pipeline capacity. A working group could be formed, and examine: • provision of real-time information vs following day;

Stakeholder	Comment
	• appropriate incorporation (and granularity) of LNG and demand-side data; • the COAG Energy Council rule change request; • costs and regulatory burden on business of data reporting; • appropriate reporting platform and central repositories; and • relevant arrangements operating in overseas markets.
Visy, pp. 5-6.	Visy strongly supports the increased use of the Bulletin Board to enhance information provision, and while supporting the 'one-stop shop' concept, does not consider that it should feature all relevant information. Further information to be provided could include: major shifts in production; and demand and pipeline flows (including their direction). Visy notes the importance of identifying demand zones and ensuring that every exemptions for reporting should not be allowed for dynamic and large demand points and related pipelines. Contracted and uncontracted pipeline capacity would be useful to facilitate efficient utilisation of capacity. Improvements could be made to the formatting of the Bulletin Board website.
Qenos, p. 4.	Qenos supports the recommendations to improve the Gas Bulletin Board. Qenos suggests looking at the following additional improvements: (1) Notice for planned maintenance of pipelines and production facilities (similar to the NEM); (2) Gas sales offers (similar to pipeline capacity trading notice); (3) Listing for available MSV offers – showing different parties with imbalances available on the different days; (4) Data to be available in an easily downloadable format; and (5) Improvements on the ability to download historical data.
Stage 1 recommendation: STTM simplification	
MEU, p. 2.	The MEU supports establishing a technical working group to begin analysis on the potential simplification of the STTM design. However, the MEU provides a caveat to their support of the STTM simplification investigation. Specifically, the MEU notes that the STTM design has only been in operation since late 2010 and that considerable effort went into the development of it by all sectors of the market. The MEU expresses concern that much of the learning that was achieved during this process could be lost and have to be relearned in a review. The MEU therefore considers that the report from the AEMC should stipulate that the technical working group established for the "simplification review" should include as many as possible of those actively involved in the STTM development.

Stakeholder	Comment
Stanwell, p. 6.	Stanwell does not support changes to the STTM market design without understanding how the proposed change fits into the AEMC's long term strategy for the gas markets.
SA Water, p. 1.	SA Water does not support the findings that the STTM is complex, that administration costs are excessive and that price risks cannot be managed.
ESAA, p. 4.	The ESAA supports establishing a technical working group to examine how to transition the STTM from its current design to one focussed on balancing, since this market function may provide the most valuable benefits over time.
AEMO, p. 4.	AEMO suggests a clearer high level direction for the east coast gas market is required to carry out this recommendation effectively. Consideration should be given to balancing zones, how zones would be balanced, the party performing the balancing, and the potential pricing solutions. AEMO cautions against designing a fourth type of market to be trialled at Brisbane. Such a market design should have to be designed so as to have broad support before being trialled and then rolled out in other locations.
AGL, p. 3.	AGL supports the establishment of the technical working group and the transition to a balancing market.
APA, p. 13.	APA supports the establishment of a technical working group. The STTM is highly complex and costly for the outcomes it delivers.
Energy Users Association of Australia, p. 4.	The EUAA supports the establishment of a technical working group.
GDFSAE, pp. 4-5.	GDFSAE recognises the need to establish the technical working group, but does not support the initial view to transition the STTM to a balancing market. The cost of STTM hubs become lower as more trade occurs therein, and this should be the aim of the markets. Moving to a 'net' based hub will increase costs for smaller participants and constitute a barrier to entry and an increase in market power to larger participants. The ability to opt out of the STTM will negatively impact those participants that have come to rely on the STTM.
Jemena, p. 3.	Jemena supports the proposal to establish a technical working group, with the aim of transitioning this market to a focussed balancing market design.
Origin Energy, p. 3.	Origin supports the proposal to establish a technical working group, with the aim of transitioning this market to a more focussed balancing market design.

Stakeholder	Comment
QGC, p. 1.	QGC considers that the review needs to include gas market operations as a key focus area, which can incorporate improvements to the STTM. The focus area would focus on establishing "within day" trading flexibility to enable market participants to manage the market dynamics associated with the commissioning of LNG trains.
Santos, p. 4.	Santos considers it is encouraging that the review will examine the broader market design framework, and supports the establishment of a working group. Santos supports setting appropriate objectives and deliverables to redesign the markets for future needs.
Qenos, p. 2.	Qenos suggests the AEMC give consideration to the time required for Facilitated Markets (such as the STTM) to develop before making significant changes.
Visy, pp. 2-5.	Visy supports simplifying the STTM to reduce cost and improve liquidity where possible, but not at the expense of the market functions that are important and necessary for providing options to gas consumers and providing transparency to the greater market.
Stage 1 recommendation: harmonising the gas day start times	
MEU, p. 2.	The MEU supports harmonising the start time of the gas day for the reasons provided in the draft report.
Alinta, p. 2.	Alinta welcomes consideration of harmonising the start of gas days across the DWGM and STTM.
Stanwell, p. 6.	Stanwell supports harmonising the start time of the gas day. Gas day should be harmonised based on the minimum cost of change (ie minimum number of meters need to be changed).
Australian Paper, p. 3.	Australian Paper consider that harmonising the gas day start times across the east coast gas market is a welcome step to promoting an efficient and competitive market.
Orora, p. 1.	Orora supports the harmonising of gas day start times across all east coast jurisdictions.
ESAA, pp. 4-5.	The ESAA supports harmonising gas day start times but notes that, given the range of system, operational and contractual changes this may necessitate, additional consultation on this issue may be required.

Stakeholder	Comment
APPEA, p. 6.	APPEA supports a move to harmonise the gas day start times.
AEMO, p. 5.	AEMO supports consideration of harmonised gas day start time, while noting concerns over the costs of implementing the harmonisation.
AGL, p. 3.	AGL supports harmonisation of gas day start times, with a 12am-12am gas day. It notes that the costs of changing systems and meters will not be material, but would need to further consider contractual implications.
APA, pp. 13-14.	APA provides in-principle support to the harmonisation of gas day start times. It provides an estimate of costs associated with modifying the coding of the flow computers on its pipelines (estimated $1-2 million). APA outlines other technical and legal changes that will need to be made, the costs of which will be passed onto consumers. Therefore, consideration needs to be given to the expected benefits of the harmonisation.
EnergyAustralia, p. 3.	EnergyAustralia supports harmonisation of gas day start times and suggests 6am as an appropriate time. It considers that this issue is not urgent and can be considered with other harmonisation considerations.
GDFSAE, p. 5.	GDFSAE supports harmonisation of gas day start times. Any material issues could be worked out in the respective consultative forums, and a rule change could enact the recommendation. GDFSAE suggests that intra-day trading and extended trading hours could be pursued.
Jemena, p. 3.	Jemena is supportive of harmonisation of gas day start times.
Origin Energy, p. 3.	Origin supports the harmonisation of gas day start times, but notes the practical complexities around this, including the need for system and operational changes and contractual review.
QGC, p. 1.	QGC supports harmonising gas day start times, and considers that it could be examined as part of a broader harmonisation workstream.
Santos, p. 4.	Santos supports harmonising gas day start times, and suggests 6am eastern standard time for all gas day start times. There would be minimal cost in administering the change, from Santos' perspective. Santos does not see a need to align start times with the NEM.

Stakeholder	Comment
Visy, pp. 6-7.	Visy strongly supports the alignment of gas day start times between markets. The particular time is not important but it should be chosen with consideration to minimising associated costs. Mechanisms need to be in place to require gas suppliers to accommodate new market times that do not align with the gas day start times in current and legacy gas supply contracts. Also, a change to gas day start times should be used as an opportunity to align windows and horizons for bidding and nominations in respective markets, to reduce transaction and system costs for parties participating in multiple markets.
Stage 1 recommendation: DWGM rule changes	
MEU, p. 2.	The MEU supports removing the current limitation in the National Gas Law on who can submit DWGM rule changes for the reasons provided in the draft report.
ESAA, p. 5.	The ESAA supports removing the current NGL limitation on who can submit DWGM rule changes.
AGL, p. 3.	AGL supports the removing the current limitation in the National Gas Law on who can submit DWGM rule changes.
EnergyAustralia, p. 3.	EnergyAustralia supports the removing the current limitation in the National Gas Law on who can submit DWGM rule changes. However, it notes that it may be better to delay this change until the completion of the review to ensure that rule changes are considered in the context of the overall gas market development strategy.
GDFSAE, p. 5.	GDFSAE supports removing the current NGL limitation on who can submit DWGM rule changes.
Jemena, p. 3.	Jemena supports removing the current NGL limitation on who can submit DWGM rule changes.
Origin Energy, p. 3.	Origin supports removing the current NGL limitation on who can submit DWGM rule changes.
Santos, p. 4.	Santos supports removing the current NGL limitation on who can submit DWGM rule changes. It would reduce the time taken to implement a successful rule change request and allow all eligible participants to request a change. It would also go towards harmonising the facilitated markets.
Visy, p. 7.	Visy supports removing the current NGL limitation on who can submit DWGM rule changes.

Stakeholder	Comment
	Stage 2 Directions: Redesigning the STTM
MEU, p. 3.	The MEU considers that instead of addressing the reasons why there are shortcomings about how the STTM is being used, it appears a decision has already been reached that there is a need to simplify the STTM process, apparently because some stakeholders have identified that simplification would reduce the costs they incur. The MEU states that simplification of the STTM is likely to result in a reversion to the original gas balancing approaches which were seen as not being transparent, did not clearly identify the costs involved, and nor did they provide a transparent or equitable mechanism for allocating the costs incurred in gas balancing
Orora, p. 3.	STTMs are no replacement for GSHs and they should be used only for balancing gas on a daily basis. Orora believe they are overly complicated, risky and add significantly to the cost of gas. Orora consider there should be no need to trade all gas through a STTM, just balancing gas as this would greatly reduce the costs of STTMs to gas users and retailers alike.
Alinta, p. 1.	Alinta broadly agrees with the proposition that the design of the STTM is overly complicated and imposes unnecessary operational and administrative requirements on participants, adding a level of complexity for participants that operate over multiple jurisdictions/supply hubs. As such, Alinta agrees that the STTM could significantly benefit from greater operational consolidation with the other facilitated markets. However, Alinta considers that it is not the case that these improvements can only be gained from transforming the STTM into a voluntary balancing market and that, doing so, would mark a regressive step on the path of market reform.
Stanwell, p. 2.	Stanwell does not support redesigning the STTM without first understanding how this strategy fits into the AEMC's long term vision for the gas markets. Stanwell agrees with the AEMC assessment that the STTM is expensive to operate and participate in. However, Stanwell states that a review of the STTM operating costs may identify areas for cost reduction which could be achieved without redesigning the whole STTM model.
SA Water, p. 2.	SA Water does not support transition to a balancing market structure for the STTM without clear definition of its operation and economic advantages.
CQ Partners, p. 2-4 & 8.	CQ Partners considers that the current STTM design is not complex and it represents a low cost market with no significant barriers to entry for customers. While CQ Partners considers that a review should be undertaken to determine if the AEMO STTM operating costs can be reduced, this should not be interpreted to mean that the STTM costs are too high and therefore there needs to be a redesign of the market. CQ Partners state that the review has omitted the critical element of the STTM being that it effectively

Stakeholder	Comment
	guarantees the supply of gas to all STTM users. CQ Partners states that to be effective at managing the security of supply, the STTM must be mandatory. CQ Partners consider that the STTM has allowed major gas customers to access gas on these markets and given them the ability to more actively manage their gas requirements. CQ Partners state that historically gas producers have been reluctant to contract directly with major gas customers and these customers have largely had to contract bilaterally with the major gas retailers. CQ Partners considers that the volume of gas traded has been underestimated by the AEMC in the draft report and that the premise that the level of trading liquidity between different entities across the STTM hubs is generally low is therefore not factual. CQ Partners provide two reasons as to why trades may appear as being within-participant when in fact they are not: (1) clients make use of their own fixed cost haulage contracts that have spare capacity; and (2) third parties have their own fixed cost haulage contracts that have spare capacity. CQ Partners consider that better alignment of the timing of gas contract nominations with the STTM nomination timelines would significantly improve the ability of customers to manage STTM price risks but note that this would not occur voluntarily and so would likely require regulatory intervention.
Australian Paper, p. 3.	Australian Paper recommends undertaking a review of the current costs incurred by AEMO in operating the STTM hubs should be implemented to identify processes that could improve efficiency and reduce costs.
ESAA, p. 4-6.	The ESAA considers that the STTM is overly complicated for the purpose it is currently serving and may be imposing unnecessary transaction costs on market participants. The ESAA does not support the trialling of a simplified market design at the Brisbane STTM Hub prior to undertaking the long term strategic assessment of facilitated markets. The ESAA considers the evolution of the Wallumbilla GSH to incorporate a single trading product and balancing services may remove the need for the Brisbane STTM hub in the future.
APPEA, p. 6.	APPEA considers that the differences between the current facilitated markets add to costs for participants and can be a barrier to entry, particularly for smaller companies.
APA, p. 13.	The STTM is highly complex and costly for the outcomes it delivers. There is limited scope for trade at demand centres and balancing services have emerged as the most prominent and effective contribution to gas market operation. The gas supply hub model has more potential to develop and stimulate gas trading than the STTM model. APA supports paring back the STTM to provide gas balancing only.

Stakeholder	Comment
EUAA, pp. 4-5.	The EUAA questions whether the Brisbane STTM is necessary given the development of the Wallumbilla Gas Supply Hub. It notes the importance of gas balancing and the ability of users to manage their commercial risk by trading in the STTM.
EnergyAustralia, pp. 5-6.	EnergyAustralia supports the creation and enhancement of facilitated markets at strategic supply points and at all major demand zones. It notes that moving commodity trading upstream and removing complexities from the price should enable a cleaner price, but recognises that this will make it harder for customers to participate directly in the market and will require registration in two markets, as well as creating the need for a capacity contract. It notes that there are differences in needs of participants in different locations and that this may affect the design of markets at each location. Intraday trading is supported. The current ex-ante price at the STTM hubs is important and should not be removed from the market. The STTM objectives should be redefined before reforms are pursued. EnergyAustralia is concerned that a voluntary STTM in Brisbane would lead to the abolishment of the Brisbane hub. A balancing market in Brisbane may be cheaper but it will come with a loss of transparency. The trialing of a different market design may not provide insight into its applicability in other locations. EnergyAustralia recommends further work be done on simplifying the STTM design before a voluntary market is trialled in Brisbane. A balancing only market may not be needed if participants can utilise upstream Gas Supply Hubs to balance their portfolio.
GDFSAE, pp. 5-6.	GDFSAE does not support the initial view to transition the STTM to a balancing market. The cost of STTM hubs becomes lower as more trade occurs therein, and this should be the aim of the markets. Moving to a 'net' based hub will increase costs for smaller participants and constitute a barrier to entry and an increase in market power to larger participants. The ability to opt out of the STTM will negatively impact those participants that have come to rely on the STTM.
Origin Energy, p. 4.	Origin considers that a simplified STTM based around a balancing market is a reasonable conclusion given the difficulties in developing significant volume of commodity trading at points so remote from production. Origin would like to see consideration of the cessation of the Brisbane hub (including balancing), with balancing to be carried out at Wallumbilla.
Santos, p. 5.	Santos considers that this review process is an opportunity to redesign the facilitated markets for the future.
Visy, pp. 2-5.	Visy considers that the STTM is complex, and this relates to the number of functions that it has. A review of the ancillary risks and functions could be conducted to simplify the market where possible.

Stakeholder	Comment
	However, Visy does not support the scaling back of the STTM to a balancing only market, and does not believe that the STTM should be voluntary. Visy points out that the STTM is the product of every day buying and selling, and converges to contract prices over time. It is a source of transparency, and can illustrate market dynamics. The STTM (and DWGM) provides competitive supply options for consumers of gas, which is helpful given the difficulty in buying from few, large suppliers. The STTM also allows users to buy gas at the city gate, thereby not requiring gas transport for that particular amount of gas, which is important given concerns around access to capacity. Costs of the STTM should be reduced where possible, but some cost is justifiable in order to have a properly functioning market.
Qenos, p. 2.	Qenos is concerned that replacing the STTM with a voluntary gas balancing market would: (1) Reduce transparency and not enable real price discovery; (2) Make it more difficult for participants to actively manage their risk. In particular, the STTM allows companies to balance risk and price; and (3) Discourage gas consumers from participation in the spot market. Qenos considers that the main benefit of STTM participation is being able to assess and directly manage the risks associated with gas purchasing. Qenos states that this ability provides a more level playing field in negotiations with upstream suppliers.
Qenos, p. 3.	Qenos states that the STTM is starting to develop to a point where it is providing an alternative to or used to supplement long term supply contracts as per its original intent. Qenos states that since the start of the year, it has been advised of two new product offerings being developed where gas supply is linked to the STTM gas market. Qenos supports a review of AEMO costs and an investigation processes into how to simplify, improve efficiency and reduce the overhead costs incurred in the operation of the STTM. Qenos believes that significant savings can be achieved without stripping the STTM of its original objectives.
Qenos, p. 3.	Qenos notes that if significant changes are made to the STTM, they need to be accompanied by the establishment of an alternative ex-ante price mechanism. Qenos does not consider that further development of the GSH at Wallumbilla would be an adequate substitute as it would require participants to separately contract pipeline transportation capacity.
Qenos, p. 3.	Qenos recommends that the AEMC investigate what changes are required in the timing nominations by upstream producers and pipeline.

Stakeholder	Comment
Stage 2 Directions: Reconsider the design of the DWGM	
Alinta, p. 2.	Alinta supports consideration of alignment of the market price cap parameters between the existing DWGM and STTM. Alinta also supports consideration of greater alignment and consolidation of prudential arrangements between existing gas markets. Alinta suggests the review could move one step further and implement the netting off of gas positions across facilitated markets immediately.
ESAA, p. 4.	The ESAA considers there is merit in expanding the terms of reference of the STTM working group to include examination of the DWGM, given it will also be ongoing area of focus for the AEMC.
AEMO, pp. 3-4.	AEMO outlines key considerations regarding the role of the DWGM and its current market design. AEMO notes that the majority of the trading in the DWGM is done at the margin. Rather than being a problem of market design, it reflects the underlying dynamic of the gas industry's structure. It is more than just a spot market, providing participants with a balancing mechanism. AEMO plays a role in maintaining system security through its system operation role and through the scheduling of the market. Given these other functions, it should not be concluded that the only value from the DWGM is from inter-participant trade. The cost of operating the market should not be based solely against the volume of inter-participant spot trades.
AGL, p. 3.	AGL believes that the AEMC should consider whether the existing intra-day trading design is fit-for-purpose given gas-fired generation has not had as significant an impact on the Victorian gas market.
APA, p. 15.	APA supports a more in depth analysis of the DWGM and its future role and structure in Stage 2 of the review. It considers that the DWGM is highly complex and costly for the outcomes it delivers. Gas trading is very limited in the DWGM and the market operates primarily as a mechanism to allocate pipeline capacity and trade imbalances. APA also notes that consideration could be given to AEMO's operation of the system with respect to its role in maintaining security of supply and planning and security standards in Victoria.
EnergyAustralia, p. 3.	EnergyAustralia supports the establishment of a technical working group to consider the design of the DWGM. It is concerned that the review proposes to reduce the volume of trade through the STTM and DWGM, and the bias to embedding the primary role of long term bilateral contracts. Stage 2 should be focussed on increasing competition, liquidity and transparency.
GDFSAE, p. 5.	In advance of the more detailed consideration of the DWGM, GDFSAE makes several observations about the DWGM: • the DWGM facilitates trade between retailers, users and producers, notably where supply concerns have existed;

Stakeholder	Comment
	• the DWGM is reasonably liquid; • legacy contracts and unmanageable charges that undermine prices and forward trading are issues; and • forward instruments do not trade as they do not manage risk and therefore cannot be used in place of physical injection. Also, links between costs and causes are worthy of further consideration.
Origin Energy, p. 4.	There is merit in considering whether the originally stated objective of the DWGM - to support full retail competition and encourage diversity of supply and upstream competition - remains relevant, and whether the current market design is considering those objectives efficiently, and if not, whether the objectives and design needs to be reconsidered. Origin supports AEMC's suggestion that the balancing aspect of the market be harmonised with that in the STTM and the commodity element with the Gas Supply Hub. The process would need to consider the effect on AMDQ and AMDQCC.
Santos, p. 5.	Santos believes that the review process is an opportunity to redesign the facilitated markets for the future. Any changes would need to ensure that the market as a whole benefited, with the benefits and costs to be clearly articulated.
Visy, pp. 2-5.	Visy does not believe that the DWGM should be voluntary. Visy points out that the DWGM is the product of every day buying and selling, and converges to contract prices over time. It is a source of transparency, and can illustrate market dynamics. The DWGM is a more mature and liquid market than the STTM. The DWGM provides competitive supply options for consumers of gas, which is helpful given the difficulty in buying from few, large suppliers. Costs of the STTM should be reduced where possible, but some cost is justifiable in order to have a properly functioning market.
Stage 2 Directions: Introduce capacity rights to the DWGM	
MEU, pp. 4-5.	The MEU states that, with regard to investment, the regulatory process is focussed on assessing augmentation of the DTS for the benefit of Victorian gas consumers, and consumers have not reported concerns that a lack of investment has been a concern. Further, consumers have not reported significant concerns with the performance of the DTS. The MEU considers that the DWGM along with the DTS has proven to be very resilient and reliable for many years in providing for the needs of Victorian consumers. The MEU states that in recent times, there has been a concern stated which is related to expectations for increased gas transport capacity to provide export to other regions and so the question then arises whether Victorian consumers should have funded augmentations of the DTS to enable greater export to other regions.

Stakeholder	Comment
	The MEU does not consider that Victorian gas consumers should pay for the infrastructure needed to export gas and notes that this has been reflected in the regulatory determinations on the DTS. The MEU does not object to the setting up of a market where unused capacity can be traded to other parties. The MEU sees that this is a sensible approach and will provide more efficient use to the limited capacity that the DTS has. However, the MEU is concerned that the issue of trading capacity rights might result in Victorian consumers suffering when that capacity is removed from supplying gas to Victorian users for the benefit of users in another region.
ESAA, p. 6.	The ESAA supports the AEMC examining the potential to introduce capacity rights to the DWGM with the objective of better facilitating market-led investment in network expansions, balancing the advantages of access to capacity provided by the current system. The ESAA notes that this analysis must give consideration to the potential impact on AMDQ and AMDQCC.
APA, pp. 8, 15.	APA is supportive if further investigating this recommendation, although it cautions against measures that may render the DWGM more complex. It notes that AEMO has previously indicated that the introduction of any further complexity could result in the failure of the Market Clearing Engine. Any consideration of intervention to support capacity trading must be aware that any weakening of the link between investment and firm capacity is likely to undermine future investment in primary capacity.
GDFSAE, p. 6.	GDFSAE notes that the allocation of capacity rights is "one approach" in allocating capacity, as well as the development of nodal trading points.
Origin Energy, p. 4.	Origin suggests that consideration of this issue must take into account the process for how capacity rights could replace or operate alongside AMDQ and AMDQCC. Given AMDQCC is obtained from shippers through an auction process, it is important that shippers are still able to access the rights associated with AMDQCC that they have paid for.
Stage 2 Directions: Develop a long-term strategy for the location of facilitated markets	
AEMO, p. 6.	AEMO concludes that “following extensive industry consultation and analysis of the issues raised through the GSHRG, AEMO supports the view of the majority of industry participants to implement a Moomba trading location.”
Orora, p. 2.	Orora is supportive of the establishment of a Moomba GSH. Orora also state that it “is not logical that the development of a Moomba gas hub would lessen liquidity of the Wallumbilla gas hub.”

Stakeholder	Comment
Origin Energy, p. 5.	Origin states that it would be opportune to develop a long term strategy that holistically considers the optimal number and location of facilitated markets. Origin states that an efficient and integrated east coast gas market requires that the location of each market and the model at that location is appropriate and fit for purpose, and that the markets individually and collectively deliver value to market participants.
ERAA, p. 1.	ERAA states that any medium or long term market based development initiatives to be explored in Stage 2 of the AEMC's review must only be considered where there is a demonstrated market failure and be subject to a robust cost benefit analysis.
Hydro Tasmania, pp. 2 & 4.	Hydro Tasmania proposes that the AEMC should have a "blank sheet" approach to market design. The "ideal" market should then become an objective to be reached in the long term and it should provide a guide for the decisions which need to be made in the shorter term. Hydro Tasmania is of the view that the shorter-term changes identified in the draft report should be held off and only considered as part of the "blank sheet" approach.
Stanwell, p. 1.	Stanwell is of the view that the AEMC has moved away from long term fundamental, visionary changes to the gas markets and is instead continuing to support piecemeal development. Stanwell states that the AEMC is recommending changes to the STTM, DWGM and Wallumbilla GSH without first developing a clear long term strategy.
EUAA, p. 5.	Members of the EUAA support the continued development of the Moomba GSH to serve large gas users in South Australia, New South Wales and Victoria and circumvent physical constraints on the QSN link. The submission does not specify a preference for implementation timeline.
QGC, p. 4.	QGC supports the active encouragement of new participants/customers into the Wallumbilla GSH (as opposed to creating a new pricing point). However, QGC notes that, while a Moomba hub may appear a simple, logical and appropriate response for increasing participants' access to supply, it does change the nature of the market and trading dynamics. QGC welcomes the AEMC's proposal to consider the liquidity issues in Stage 2 but is concerned that the recommendation is too narrowly defined in that it will only consider "how and when such a design will best fit into the wider east coast framework".

Stakeholder	Comment
	QGC notes that they have outlined an alternative model where Moomba would be considered a receipt point for the Wallumbilla GSH (trades would be based off the Wallumbilla price ex transport). QGC states that the recent AEMO consultation process was useful in understanding physical hub design but it also raised important strategic questions that were “outside” scope of its consideration, particularly the liquidity impacts and the role Moomba plays in the overall COAG Energy Council Vision for the east coast gas market. QGC considers that fundamental to considering the introduction of a Moomba trading location are the principle issues of the lack of access to short-term competitively priced pipeline capacity and the importance of concentrating liquidity need to be addressed.
APA, p. 17.	APA supports the AEMC direction for Stage 2 to develop a long term strategy for the location of facilitated markets and that this work should consider the appropriate structure and timing of any future Moomba GSH.
Santos, p. 5.	Santos supports the development of a Moomba GSH but suggests that it should be included in a ‘long term strategy for the location of facilitated markets’. Santos recommends that any decision should be made in the context of the broader and priority list of issues for this review. Santos would welcome the opportunity to assist the AEMC in determining the best approach for Moomba. Santos states that both the deodorised nature of MAPS gas and the current limited volume of uncontracted gas from Moomba should not impact on the decision on a delivery point or hub.
Alinta Energy, p. 3.	Alinta supports the AEMC recommending reforms in the area of harmonising facilitated markets and supports the development of a consolidated long term strategy for facilitated markets. Alinta is supportive of additional hub development at Moomba if the benefits of doing so clearly outweigh the costs of establishment. Alinta states it would be interested in the Stage 2 report assessing whether the development of an additional trading hub may actually mask the real inhibitor to trade – the inability to transport gas within the east coast market at a reasonable price. Alinta’s preferred approach would be one that conceptualised an arrangement in which both additional hub development and capacity trading can be developed in tandem.
AGL, p. 4.	AGL states it is interested in further analysis on the benefits of additional trading locations, including at Moomba, which may be of benefit to the east coast market as a whole. However, AGL considers that it may be more beneficial to the market to resolve issues with the STTM markets (primarily costs of participation) and Wallumbilla (low trading liquidity) before using limited resources to create even more trading hubs based on models that have not as yet delivered their predicted value.

Stakeholder	Comment
Australian Paper, p. 3.	Australian Paper further considers that the option of establishing a STTM at Moomba should be on the list of actions being considered by the AEMC.
GDFSAE, p. 6.	GDFSAE suggests that liquidity concerns and concerns surrounding the fact that a Moomba GSH may lock in market structures that are revealed to be sub-optimal following the conclusion of this Review may be overstated. However, GDFSAE notes that any development at Moomba should be considered in the light of possible outcomes of this Review and allow for further development.
ESAA, p. 5	The ESAA supports the AEMC examining the appropriateness of the facilitated market designs and believes the analysis could be incorporated into a long term strategy for the location of facilitated gas markets.
Stage 2 Directions: Further develop the Wallumbilla GSH	
Stanwell, p. 2.	Stanwell supports the AEMC's intention to complement the work being undertaken by AEMO on the Wallumbilla GSH. Stanwell supports the AEMC's proposed study into the effects on the competitive landscape for the provision of hub services (including the possible need for economic regulation).
CQ Partners, p. 6.	CQ Partners commented that considerable cost and effort is being put into trying to improve the Wallumbilla GSH and that their view is that it is unlikely that there is a positive net benefit associated with this. CQ Partners also expressed concern that the general focus of the Review is to change the design of the three markets that are working efficiently to bring them in line with the one market that, in their opinion, is not working - the Wallumbilla GSH.
ESAA, p. 6.	The ESAA has reservations regarding the proposal to investigate the effects on the competitive landscape for the provision of hub services at Wallumbilla, including the possible need for economic regulation. The ESAA notes that it is important to consider how market participation and liquidity can be enhanced over time, but any consideration of economic regulation should ultimately be informed by an assessment of overall costs and benefits and have regard to existing rights.
AEMO, pp. 6-7.	AEMO is currently undertaking a review of hub services to consider the necessary services required to facilitate a single trading zone at Wallumbilla Gas Supply Hub. An important consideration is whether there are sufficient services to facilitate trade of the single product and whether the competitive environment for hub services is appropriate to support the proposed market model. Market participants currently have access to services such as compression and redirection at Wallumbilla, to a level sufficient to support the current trading needs.

Stakeholder	Comment
AGL, pp. 3-4.	AGL supports a low cost Gas Supply Hub model where trades are voluntary. AGL does not support a model where APA (as a monopoly provider) is made the hub operator.
APA, pp. 16-17.	APA supports the development of the Wallumbilla Gas Supply Hub into a single trading product. APA has previously proposed a model wherein it provides a new hub service to the market that would facilitate trades across the three trading nodes and integrate these nodes for trading purposes into a single location. The hub service would be offered at a set, up front price published on the hub trading platform, and participants would be able to use their own contracted hub services or purchase services through trade, as an alternative to the APA hub service. APA believes that it can provide a firm hub service on most days, which would "easily accommodate" the current trading levels at Wallumbilla. The hub services model will allow future demand for the service to provide clear investment signals for the installation of additional capacity at the site, which will facilitate the growth of the market as a whole. APA provides comment on other models proposed by AEMO, noting that they will involve significant costs that are not proportionate to the size of the market. A compulsory market would involve "significant smearing" of costs without providing any benefit. APA does not believe that economic regulation of hub services is necessary.
APLNG, p. 2.	APLNG supports the current work stream being undertaken by AEMO.
EnergyAustralia, p. 8.	EnergyAustralia supports the Wallumbilla Gas Supply Hub work being done by AEMO. EnergyAustralia supports a single product at Wallumbilla as a natural and necessary step towards the COAG Gas Market Vision.
GDFSAE, p. 6.	GDFSAE supports the development of Wallumbilla Gas Supply Hub. It notes that in order to support the development of a traded futures/OTC market a single product must deliver a firm level of service, and the market must capture the bulk of trades. Certainty is required to support a futures market.
Origin Energy, p. 5.	There is merit in AEMO's technical working group to investigate the effects of on the competitive landscape for the provision of hub services, including the need for economic regulation. A workable single hub model should preserve the rights of existing users of hub services and facilitate the competitive provision of services on a voluntary basis by allowing existing rights holders to use and trade their own services. Origin supports a voluntary, low cost gas supply hub model, and cautions against a compulsory hub services model.
QGC, pp. 4-5.	QGC considers the Wallumbilla Gas Supply Hub as central to promoting liquidity in the east coast gas market and supports its development, including AEMO's work on developing a single Wallumbilla hub product. Firm service is needed to develop futures/OTC markets. Addressing capacity hoarding is likely to reduce the need to introduce alternative market design mechanisms, such as new trading hubs, and enabling more capacity trading would likely support the development of the

Stakeholder	Comment
	Wallumbilla Gas Supply Hub by encouraging greater participation and liquidity therein. Thereafter, natural trading hubs will then have an opportunity to develop. There is a need to concentrate liquidity at one trading point (Wallumbilla). This will enable a market of sufficient depth to emerge and produce an efficient reference price, which is necessary if the ASX futures contract is to be successfully traded.
Santos, p. 5.	Priority should be given to the continued development of the Wallumbilla Gas Supply Hub. This hub model should be rolled out if and when future hubs are agreed. There are improvements that need to be made at the Wallumbilla hub. Santos warns against premature conclusions about the need for economic regulation for the provision of hub services.
Stage 2 Directions: Consider potential measures to better facilitate pipeline capacity trading	
MEU, pp. 5-7.	The MEU supports the move to provide a market for gas capacity trading. The MEU agrees that capacity trading can increase the utilisation of pipelines but there are a number of circumstances where there is an incentive on the rights holder not to offer capacity as this might result in a less profitable outcome for the rights holder.
Orora, p. 2.	Trading of gas pipeline capacity should be available to allow for re-allocations of capacity from large user's retailers to large users relatively simply and for minimal cost. Orora considers the same is true for the trading of capacity on the laterals to gas transmission pipelines.
Stanwell, p. 2.	Stanwell supports the AEMC's investigation into measures to better facilitate pipeline capacity trading but notes that existing property rights must be protected.
ESAA, p. 6.	The ESAA supports the AEMC investigating and considering potential measures to better facilitate pipeline capacity trading.
APPEA, p. 11.	APPEA supports the introduction of a pipeline capacity trading initiative. APPEA considers that efficient access to pipeline capacity is fundamental to market development and must be a key feature of any reforms. APPEA also supports moves to improve transparency in pipeline markets that interface with the facilitated markets, so capacity can be trade more actively.
AEMO, p. 2.	AEMO is cautious about expanding the BB to incorporate an additional capacity listing service in addition to the listing service at WSH. Any additional capacity listing service will provide limited benefit without an underlying capacity trading framework.

Stakeholder	Comment
AGL, p. 4.	AGL considers that capacity trading is a constraint in developing liquidity in the gas market, second only to supply constraints. It considers that the efficient allocation of gas is tied to the conditions in the transmission segment of the supply chain, and that consideration of the current regulatory framework and market arrangements is relevant to enable gas to flow to where it is most valued. AGL will undertake internal work on capacity trading in parallel with Stage 2 of this review, including consideration of contractual and access issues (such as grandfathering current transmission arrangements until the conclusion of their commercial terms) or the potential to shift to an open access regime.
APA, pp. 5-6.	APA supports the development of the secondary pipeline capacity market. While recognising that there has so far been little secondary capacity trading, the development of the gas market, particularly with the new and flexible demand from LNG producers has the potential to stimulate the market. It advocates market driven solutions, and urges any intervention in the market to carefully identify the relevant issues potentially preventing secondary trade from occurring. The underlying nature of the east coast pipeline capacity market may impact its liquidity, such as the tendency of single pipeline industrial shippers with long term needs for firm capacity having little interest or demand in trading capacity.
APA, pp. 6-7.	In examining the drivers of secondary capacity trading, APA believes the AEMC should give further consideration to the following factors: • the nature of the traded secondary capacity service (as opposed to the service provided through primary contracts), and the degree to which this service can already be traded; • the current actual transaction costs or other factors involved in executing a capacity trade; • the current market for trading in capacity, and potential reasons why there are limited trades, including whether there is a significant current unmet demand for capacity trading; • whether those that may express a wish to purchase pipeline capacity are actively seeking capacity in the current market, or whether their demand for traded capacity relates to a future period; • the likely scope of future demand for capacity trading, and when that demand may arise, in particular whether it is likely to arise at peak times when capacity is likely to be utilised by other contracted parties (that is, there is physical congestion and therefore limited unutilised capacity to trade);

Stakeholder	Comment
	• whether shippers are holding on to capacity for commercial reasons, as suggested by the Productivity Commission, for example because of the option value of future capacity as a risk management tool in an uncertain demand environment, and in that respect there is not a market failure but an efficient response to market circumstances; and • whether imminent changes to the market with the start-up of the remaining two LNG facilities, will in themselves provide stimulus to the capacity trading market by potentially placing a higher value on existing capacity that may stimulate trade.
APA, pp. 10-11.	APA is concerned that the AEMC is looking to the access regime for primary capacity to enact changes in the secondary capacity market. APA does not believe that this is the appropriate location for intervention as the access regime regulates the relationship between the pipeliner and shipper, not the relationship between shippers, which is the locus of the secondary capacity trading market. APA outlines some benefits of a secondary capacity market over a regulatory approach through the access regime.
APLNG, p. 2.	APLNG considers that capacity trade should only be done through novation. Ease of transfer points is critical. All capacity trades should be posted to the Bulletin Board, including the capacity amount, receipt and delivery points, term and price. The failure to release issue needs to be resolved. Capacity holders will need to be incentivised to increase the capacity utilisation of critical sections of infrastructure.
APGA, pp. 5-6.	APGA supports further work being carried out in Stage 2 to fully articulate the barriers to entry in secondary capacity trading before proposing solutions. This should be done through a quantitative analysis of gas flows and responsiveness to changed conditions. APGA makes a distinction in the discussion on secondary trading in the context of the greater demand for flexibility. It notes that interruptible and as available service offered by pipeline operators are not strictly secondary capacity arrangements. Short term flexibility is available to market participants through pipeline operators and the secondary market, however short term firm options such as weekly or monthly firm capacity are more likely to be available through the secondary market. APGA also notes the use of a third type of secondary trade, which was not mentioned in the Stage 1 Draft report. Operational capacity transfers offer reduced transaction costs to traders and allow a temporary transfer of rights and obligations, and therefore can be seen as combining the temporary transfer of bare transfers with the obligation transfer of novation. APGA cautions against making changes to the access regime to support secondary capacity trading.
EUAA, p. 4.	EUAA members are supportive of a regime to support capacity trading improvements. EUAA welcomes suggested changes to the Bulletin Board, as outlined in the Stage 1 Draft report. Having the ability to trade excess gas would enable more efficient trades and liquidity if buyers can access transport capacity and understand the feasibility of transporting gas.

Stakeholder	Comment
	The EUAA noted that each Australian state has a level of regulatory access arrangements for infrastructure, but that no state or territory has their regime certified. The lack of clear or uniform infrastructure access regulations at a national level limits the ability of parties to access gas infrastructure on a recognised basis.
GDFSAE, p. 6.	GDFSAE is encouraged by the discussion on capacity trading, and welcomes the benefits of defining the role of firm capacity, exploring the value of tradeable point to point services, the conditions required to deliver a traded environment, reducing the impact of infrastructure participants on trading within hubs, managing participants concerns around monopoly services, and the role of regulating pipeline investment inside hubs.
Origin Energy, p. 5.	Origin advocates an assessment of the challenges that may be impeding capacity trading before identifying options to address them. It suggests consideration of volumes, durations, and times of the day and year that participants are seeking capacity for, the search process and negotiation process, including transaction costs and prices, in addition to the way in which point to point rights are specified. Origin welcomes analysis of capacity trading regimes in other countries, but urges the AEMC to consider the potential for negative consequences from interventionist regimes. The AEMC should not move to another model of capacity trading until incremental changes are given time to be implemented.
QGC, p. 2.	QGC considers that Stage 2 of the review must deliver specific recommendations, a defined set of reform milestones, and a timely implementation plan for addressing the lack of access to short term capacity. The AEMC should investigate the issue of contract provisions that may affect capacity trading. QGC will develop a set of specific market design principles to guide the consideration of potential capacity trading options with the aim of recommending an overall preferred solution. One of the potential market designs is the Oversell and Buyback scheme.
Visy, p. 6.	Information on contracted and uncontracted pipeline capacity needs to be made available in a way that enables the market to identify the gap between utilisation and capacity. Such information could be used as a platform for more comprehensive pipeline capacity trading. While some pipeline owners have made commendable efforts to promote some capacity trading, these pipeline owners may not be acting in their own commercial interests, as they may be able to sell the same pipeline capacity twice - first as 'firm capacity' and secondly as 'as available' if physically unused as firm.
Qenos, p. 3.	Qenos considers that more active trading of pipeline capacity needs to be addressed before any proposed changes to the existing markets.

Stakeholder	Comment
Stage 2 Directions: Consider the strategic direction for information provision, including the Bulletin Board	
Orora, p. 2.	The Bulletin Board needs to display nominations and capacity on laterals as soon as possible to encourage trading of capacity on the laterals to gas transmission pipelines.
Alinta, pp. 2-3.	Alinta considers that compulsory reporting obligations should be required for upstream gas produces with respect to any medium term changes in the capacity of their production facilities. Alinta states that these reporting obligations should be provided to the Bulletin Board in a similar fashion to how Medium Term Projected Assessment of System Adequacy (MT PASA) forecasts are provided to the Australian Energy Market Operator (AEMO) within the NEM. Alinta further considers that these obligations should contain comparable civil penalty obligations. Alinta is of the view that reforms in this area would be beneficial in informing participant decision making and the benefits are likely outweigh the costs of improving the Bulletin Board.
Stanwell, p. 3.	Stanwell supports the AEMC's consideration of the strategic direction for the Gas Bulletin Board, including the desire to balance the cost of changes to data coverage, timeliness and accuracy against the benefits. In order to improve the Bulletin Board, Stanwell would like to see policy makers address the following: (1) ensure all important pipelines, production and storage facilities are registered and therefore required to provide data; (2) ensure data is accurate and provided in a timely manner; and (3) enhance the useability of the Bulletin Board by providing it in a database format similar to AEMO's electricity market "Infoserver."
Commercial Economics Consulting, p. 3.	Commercial Economics Consulting supports arrangements aimed at ensuring information disclosure on a consistent and meaningful basis. Commercial Economics Consulting states that information disclosure is the lubricant that ensures efficient markets and that any cost-effective mechanisms that ensure timely information disclosure are likely to be beneficial.
CQ Partners, p. 7.	CQ Partners considers that there should be a review of the cost recovery model for the Bulletin Board to ensure equitable cost recovery and better alignment to user pay principles. CQ Partners states that parties that ship gas to the STTM hubs and the DWGM are currently bearing a high proportion of the costs.
ESAA, p. 3-6.	To improve the overall useability and functionality of the Bulletin Board, the ESAA supports the following: including information on prices from the facilitated markets; developing a new long-term forecast and planning page; and expanding the scope of capacity listing to include a voluntary listing service for gas, transportation and storage capacity and working with Jemena and APA Group to determine whether their capacity trading sites can be linked to the Bulletin Board.

Stakeholder	Comment
	The ESAA broadly supports enhancing information provision where it is accurate, relevant and does not reveal commercially sensitive information. The ESAA considers that it should be noted stakeholders have previously expressed varying views as to the appropriateness and relevance of some of the informational gaps identified by the AEMC. The ESAA considers these information gaps should not be incorporated into the Stage 1 recommendations but instead they should be considered as part of the AEMC's assessment of Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change. The ESAA supports examining whether the coverage, timeliness and accuracy of information can be improved and if so, whether the benefits of any informational improvements are likely to exceed the costs. The ESAA does not support mandating that transmission tariffs are published on the Bulletin Board, to the extent that the current regulatory framework provides limited coverage options that protect pipeline businesses from having to list reference tariffs.
APPEA, p. 11.	APPEA supports that coverage of the Bulletin Board, and its associated informational requirements, be extended to large gas users. APPEA does not support any moves to include exploration and reserves information on the Bulletin Board.
AEMO, p. 2.	AEMO is supportive of the AEMC establishing a vision for the development of the Bulletin Board, consistent with the COAG Energy Council's Vision. This should be focussed on developing the Bulletin Board as a tool with which to support short- and long-term decision-making through improved transparency and availability of gas market information. This could be aimed at improving coverage and information required to support risk management in the wholesale market, as noted in the Stage 1 Report.
AGL, p. 4.	The AEMC's Stage 2 recommendations appear far-reaching with potential unintended consequences and costs. The market will benefit from more specific recommendations that clearly consider costs and benefits. Recommendations should clearly be linked to the Bulletin Board's long-term objectives, rather than attempting to address short-term uncertainties while the market adjusts to changing dynamics.
APA, pp. 25-27.	APA considers that the first step in reviewing the broader informational needs of the market is to review the information currently available to the market. Currently available information - in particular short term forecast and historical information on pipeline utilisation and flows - provides market participants with a powerful tool to understand overall gas flows and trends and to predict market outcomes. Along with changes to the Bulletin Board zones recommended by APA in its submission, market participants will be able to balance the gas market over the long term and understand short term trends. Zone definitions have not been updated with the market, and this needs to be resolved (noting it can be resolved in Procedures). Presentation of information is a concern and could be improved. APA considers that keeping information in the "private sphere" is not a market failing, but an efficient allocation of the costs of additional and specialised information to those that are likely to benefit from it. This is because information may be of more value than it costs to produce or procure. It will be important for the AEMC to

Stakeholder	Comment
	not socialise the costs of participants procuring information for their commercial needs. APA notes a number of questions that need to be answered to satisfy a net public benefit test for potential information requirements.
Origin Energy, p. 6.	Origin supports consideration of a strategic direction for information provision, including the Bulletin Board. Careful consideration must go to the informational needs of the market, identifying market failure and not opting for more information unnecessarily. Commercial positions should not be compromised, and the new information requirements need to past a cost-benefit test.
Other comments	
MEU, p. 7.	The MEU noted that the apparent advantages seen in the contract carriage model for augmentation of a pipeline, will only occur when the pipeline owner is assured that a counterparty will undertake the risk of augmentation; a counterparty is unlikely to commit to more capacity than it needs as it means that the counterparty will incur costs that it will have to carry without reward.
MEU, p. 9.	The MEU considers that the AEMC must address the issue of limited competition in production as part of its assessment.
MEU, pp. 10-11.	The MEU considers that the Stage 1 report needs to reflect the actualities of the gas markets and to recommend deeper investigation as to whether the structures (eg gross pool versus net pool, market carriage versus contract carriage) of the gas markets results in a number of the shortcomings that have been identified in the discussions to date. The MEU considers that the AEMC should examine whether the gas market would be more efficient if it were operated on a gross pool basis - in similar fashion to the electricity market.
MEU, p. 11.	The MEU considers that the AEMC must address issues associated with the implications of the contract carriage model and increasing capacity in its report.
MEU, p. 13.	The MEU considers that the AEMC should include in its report a recommendation that pipelines not subject to competition (ie, exhibit monopoly traits) should be reassessed for regulation and why the regulation (and re-regulation) process has not resulted in protecting consumers from monopoly rent taking.
CQ Partners, p. 1.	CQ Partners considers that the draft report has failed to adequately consider the NGO by not demonstrating how the suggested recommendations would, if implemented, benefit the long-term interests of consumers. CQ Partners further considers that the recommendations favour the position of the major producers and sellers of gas at the expense of consumers. CQ Partners further considers that there should have been a greater representation of large users on the Advisory Group.

Stakeholder	Comment
Australian Paper, p. 1.	Australian Paper supports the comments made by CQ Partners in respect of the lack of large users' representation in the Advisory Group members.
APPEA, p. 3.	APPEA considers it a disappointing omission that issues relating to the investment environment for gas supply have been excluded from the review.
APPEA, p. 4.	APPEA considers that rising costs have contributed to recent price rises for natural gas in Australia.
APPEA, p. 4.	APPEA rejects the notion that extending third party access regimes to, amongst other things, gas processing facilities is needed.