Australian Energy Market Commission

REVIEW

DRAFT FINAL REPORT

Review of the Victorian Declared Wholesale Gas Market

14 October 2016

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Draft 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 Declared Wholesale Gas Market (DWGM) was established in 1999 by the Victorian government, with the objective of supporting retail competition and encouraging diversity of supply and upstream competition. Today, it provides an effective gas balancing service and facilitates a limited amount of trading of gas based on short-term prices.

However, developments in the wider east coast market are now presenting new challenges and exacerbating known issues with the current DWGM market design. In this Draft Final Report, the Australian Energy Market Commission (AEMC or Commission) explains why the DWGM appears poorly placed to meet these challenges and sets out recommendations for reforming the market arrangements.

East coast gas market dynamics are significantly impacting the DWGM

At the time of its establishment, the DWGM had only very limited inter-connectivity with other sources of gas supply and demand. That permitted the market to operate relatively autonomously. However, since then, the construction of an interconnected network of transmission pipelines has linked the DWGM to markets across the east coast of Australia. This transformation has been accelerated in recent years by the commencement of liquefied natural gas (LNG) exports from Queensland, linking the wider eastern Australian market - including the DWGM - to markets overseas. LNG exports have driven a substantial increase in overall gas demand across eastern Australia from 694 petajoules (PJ) in 2014 to an expected 1,971 PJ in 2017.[1]

This increase in demand has put upward pressure on domestic prices including in the DWGM, where the average daily price reached a historic high of $6.74/GJ in the second quarter of 2016 - nearly double the level of eighteen months earlier.[2] However, a further consequence of both the linking of domestic prices to international prices (which are generally linked to oil prices), and the operational characteristics of the LNG industry, has been to increase the volatility of prices.

In particular, operational incidents related to the LNG export industry have the potential to create very large changes in the flows of gas across the east coast. For example, an unexpected shutdown of an LNG processing facility or related infrastructure could result in a large quantity of gas (of an order of magnitude similar to total east coast Australian domestic demand) suddenly being made available to the domestic market, with the coal seam gas wells primarily supplying the LNG export projects having only a limited ability to reduce supply in these instances.[3] The volatile

1 AEMO, *National Gas Forecasting Report*, Forecasting Dynamic Interface, accessed 3 October 2016.

2 AER Wholesale Statistics, available at: http://www.aer.gov.au/wholesale-markets/wholesale-statistics/victorian-gas-market-average-daily-weighted-prices-by-quarter.

3 PricewaterhouseCoopers Australia (PwC) estimates the number of shutdowns of LNG processing facilities could be in the range of zero to ten days per year. PwC, *Cost benefit analysis of gas market reforms*, May 2016, p. 54.

flows of gas caused by such incidents have the potential to create significant price volatility across eastern Australian gas markets, presenting both downside and upside risks to market participants.

During the more stable market environment of the recent past, DWGM market participants principally managed price risk through long-term Gas Supply Agreements (GSAs), with the role of the DWGM largely being to manage daily imbalances in a transparent and competitive manner.

However, the changed market dynamics have prompted a need for greater flexibility in how gas is bought and sold outside of GSAs now and into the future. Consequently, new approaches to managing price volatility risk are becoming increasingly important to participants. The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed and it is these factors that have led to a renewed focus on market development to promote efficient outcomes for consumers.

The DWGM will not support the achievement of the COAG Energy Council's Vision

In light of the above changes, in December 2014 the Council of Australian Governments (COAG) Energy Council established a set of principles, which it referred to as its Vision for Australia's future gas market.[4] The Vision is centred on the establishment of a liquid wholesale gas market, with a key outcome of this being an efficient and transparent reference price for gas.

The COAG Energy Council then tasked the AEMC to identify a roadmap to achieve the Vision. To do so, it requested that the 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").

Concurrently, the Energy Council, at the request of the Victorian Government, asked the AEMC to undertake a specific, detailed review of the DWGM. In accordance with the terms of reference,[5] the purpose of the review has been to consider whether the DWGM: allows market participants to effectively manage price and volume risk; provides appropriate signals and incentives for investment in pipeline capacity; and facilitates the efficient trade of gas to and from adjacent markets. All these attributes are consistent with the Vision.

Over the course of the review, in considering the future role of the DWGM in the market development roadmap, the Commission has assessed the current arrangements against the key elements of the Vision and, particularly, those attributes highlighted in the terms of reference. The Commission has concluded that the DWGM does not meet these objectives, and therefore will not facilitate the achievement of the Energy Council's Vision for Australia's future gas market.

4 The Vision is set out in Chapter 2.

5 The Terms of Reference are found in Appendix A.

Limited risk management options

The DWGM operates as a simultaneous spot market for both gas and access to transportation capacity on the Declared Transmission System (DTS) that underpins the DWGM. Access to the network is allocated dynamically and implicitly to market participants on the basis of bids and offers made for gas on or near the trading day in question. There is no way *within the DWGM itself*, to buy or sell gas ahead of the gas day in order to hedge spot price volatility risk.

Given that most gas industry participants – or at least their financiers – exhibit a degree of risk aversion, participants require a means of managing the financial risk associated with price variations in the spot market in order to make efficient investment decisions in upstream and downstream gas activities.

In the National Electricity Market (NEM), which has a similar spot market to the DWGM, an active financial derivatives market has emerged alongside and is settled against spot market outcomes to perform this risk management role. However, the underlying physical characteristics of gas require the DWGM spot market to be considerably more complex than that of the NEM. This complexity has not been conducive to the development of a financial derivatives market as a "side market" to the DWGM.

Consequently, market participants can generally only manage price risk in the DWGM by entering into GSAs outside of the market and bidding this gas into and out of the market in such a way as to ensure that their scheduled injections and withdrawals match. At a time when managing risk is become significantly more important for market participants, this approach appears increasingly insufficient.

Opaque longer-term pricing

Market outcomes are in part a function of the quality of information available to market participants. An effective gas market is one that can deliver to participants meaningful, market-based reference prices for gas that reflect underlying supply and demand conditions. Such prices can provide signals to drive the efficient use of gas in the short-term, while promoting efficient levels of investment in physical gas supply and gas consuming-facilities in the long-term.

While the DWGM spot price reflects immediate conditions, it is not representative of supply and demand over the longer term. Long term trades (such as GSAs) are negotiated bilaterally, with the terms and price kept confidential. A liquid financial derivatives market would increase the amount of information available to market participants to make informed decisions, but for the reasons discussed above, this has not emerged. Consequently, the existing market arrangements appear unable to support the achievement of this aspect of the Energy Council's Vision.

Limited market-driven investment in the Declared Transmission System

While it is currently possible for participants to underwrite investments in the DTS, this tends not to happen because of the "free-rider" problem that arises as a result of the

DWGM's design. As access to the DTS is allocated on the basis of DWGM market outcomes, market participants cannot obtain exclusive access rights. The lack of such rights to use the DTS means that individual market participants have limited incentives to underwrite investments in the system. Other market participants would also benefit from a capacity expansion without having contributed to its costs, and may even be able to usurp the funding participant's ability to use it.

Consequently, investment decisions in the DTS are generally the result of a regulatory process, as part of the Australian Energy Regulator's (AER's) review of the DTS Access Arrangement. Putting to one side the free-rider problem which arises from allocating capacity through the DWGM, the current regulatory approach to expansion has two substantial drawbacks compared to a market-led approach:

- the regulator is unlikely to have the same information or incentives to make efficient decisions compared to a market participant; and
- if, despite the likely improved decision making under a market-led approach an inefficient investment decision is made, the market participant, rather than consumers, would bear the cost of this decision.

Furthermore, as part of an interconnected network, investment in the DTS is increasingly made for the benefit of consumers outside of the DTS, despite the cost and risk being borne by Victorian consumers.

Indeed, the greater likelihood of efficient investment decision making and the allocation of investment risk to market participants are the reasons why market-led investment is the approach to capacity expansion used in eastern Australia outside of the DTS. The contract carriage market arrangements that operate outside the DTS enable the free-rider problem to be addressed much more effectively than under the DWGM design.

Inhibitions on trading between markets

There are currently three different facilitated market designs in operation in eastern Australia, with six different pricing points.[6] It is likely that the disjointed nature of these market arrangements is inhibiting trading across the east coast, increasing complexity and transaction costs. These factors may also be deterring participants in one market entering another.

Substantial reform is recommended

The changes underway in the wider east coast market present new challenges for the DWGM and expose shortcomings that previously obscured by its less interconnected operation and more benign market conditions. Given that the limitations result from

6 The facilitated market designs are the DWGM, the Short Term Trading Market (STTM) and the Gas Supply Hub (GSH).

features intrinsic to the existing market design, it does not appear that incremental changes could address the shortcomings effectively or durably.

To address the emerging challenges, the Commission is recommending substantial reforms to the DWGM to introduce new arrangements based on an entry-exit model that is applied widely across Europe. With the gas industry across south-eastern Australia now far more integrated domestically and internationally than it was when the DWGM was established, it is timely to update the market design to enable it to better reflect the more dynamic environment it now operates within.

The recommended reforms would create a "Southern Hub" for gas trading. This forms an important part of the Commission's roadmap for gas market development on the east coast, which seeks to concentrate gas trading at two main points: the Southern Hub, and a Northern Hub based around the existing Gas Supply Hub at Wallumbilla, Queensland. The COAG Energy Council endorsed this approach at its meeting on 19 August 2016, giving in-principle support to the establishment of the Southern Hub, subject to the finalisation of this review.

The Southern Hub model would allow for the introduction of gas trading arrangements consistent with those at the Northern Hub by unbundling the three functions currently performed by the DWGM spot market: gas trading, balancing and capacity allocation.

- **Recommendation 1:** Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the Declared Transmission System (DTS).
    - Gas trading and balancing in the DWGM currently occurs on a mandatory, operator-led basis. This should transition to the new Southern Hub model, where trading would occur on a voluntary, continuous basis. Participants would be able to trade either bilaterally or through a low cost, anonymous trading exchange, which would be the same as the Northern Hub. The Southern Hub market would continue to cover the DTS, and trade would therefore occur at a notional (or "virtual") point - bids and offers would be matched regardless of the actual injection and withdrawal points for the gas.
- **Recommendation 2:** Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.
    - Continuous balancing means that market participants would not be required to exactly balance their positions at any particular point in time. However, if AEMO, as system operator, was required to buy or sell gas to

maintain system security, the participants responsible for the imbalance would be allocated a portion of those costs.

- **Recommendation 3:** The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.
  - The existing market carriage model for allocating capacity in the DTS, and associated limited pipeline transportation rights, should be replaced with a system of entry and exit rights. These rights would enable participants to be confident that their nominated injections and withdrawals would be achieved. Entry and exit rights would be made available through a variety of channels, including secondary trading.

The Southern Hub model would result in substantial benefits

Over the course of the review, the Commission has developed the Southern Hub arrangements in some detail, and considers that their introduction would result in substantial benefits. In particular, the Southern Hub model would address the intrinsic deficiencies the Commission has identified with the current DWGM arrangements, and so facilitate the achievement of the Vision. At the same time, the implementation of the Southern Hub will not compromise and should enhance those aspects of DWGM performance that have been positive to date - retail competition and system security.

Implementing the Southern Hub arrangements would result in tangible gains for the Australian economy. PwC, which was engaged by the Commission to undertake a quantitative assessment, estimates that implementing the Southern Hub model has the potential to result in an annual incremental contribution in Australia's Gross Domestic Product of between $0.2 billion to $1.7 billion by 2040, even after implementation costs have been considered.[7]

The main benefits associated with the introduction of the Southern Hub model are outlined below.

Improved risk management

Unbundling the allocation of transmission capacity from gas trading would facilitate the trading of gas on a physical basis, over any time period. Unlike the existing DWGM arrangements, this would allow participants to manage price risk through forward trading within the market. It would also avoid many of the transaction costs involved in negotiating traditional GSAs. Participants would be able to trade products of varying durations and delivery dates through a low cost, anonymous exchange, with the same design as the Northern Hub.

In time, liquid trading of standardised physical products might provide better pre-conditions for financial derivative products to emerge than in the current market. Such products would provide a further means for market participants to manage risk.

7 PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, October 2016.

Transparent and meaningful reference prices

The prices on the Southern Hub exchange and the reporting of bilateral trades, including any liquid financial derivatives market that might also emerge, would provide market participants with transparent and meaningful reference prices. As gas would be traded over multiple periods, including over the longer term, these prices would reflect both short and long term supply and demand conditions. This contrasts to the existing DWGM, where the only transparent price is the spot price, which is reflective only of immediate conditions.

Better longer term reference prices (i.e. greater than day ahead/on the day) can provide signals to promote efficient use of gas and efficient levels of investment, throughout the supply chain.

Greater market driven investment in the DTS

Unbundling capacity allocation from the trading of gas would also facilitate a greater level of market-driven investment in the DTS.

Under the Southern Hub model, the free-rider problem that arises as a result of the DWGM's design would be mitigated by the issuance (and trading) of physical rights providing exclusive use of capacity. Market participants would be able to obtain additional rights by committing to fund capacity expansions, so improving their incentives to underwrite investments.

Investment decision making would retain some elements of the regulatory process, but would have a significantly increased role for the market to contribute to decisions. By committing to fund capacity expansions, market participants would provide signals which would be used by the AER to inform its decision making.

Such an approach is preferable because the incentives on market participants would act to provide more reliable and effective signals to the AER as to whether an investment is efficient. Furthermore, if an inefficient investment decision were to be made (despite the improved decision making process), the funding market participants would bear their proportion of the costs of this decision, rather than consumers.

Improved trading between hub locations

The introduction of a trading exchange consistent with that at the Northern Hub would provide a low cost, anonymous and transparent way for participants to trade. It would also support the implementation of common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. This should lower transaction costs and complexity for traders operating across multiple markets, encouraging greater participation and trade across the east coast.

Reduced barriers to entry

Greater flexibility in how market participants buy and sell gas and manage risk should allow a greater variety of market participants to enter the market and subsequently expand. The Southern Hub would provide an alternative to bilateral contracting, which may be particularly difficult for smaller new entrants, as they may not have the resources to negotiate on an equal basis with incumbents. Instead, if new entrants – whether they be small producers, gas users or participants in other east coast markets – have accurate price information, they will be more readily able buy or sell gas on the market on a level footing with other players. A liquid market can therefore encourage participation and promote competition.

Improved management of system security

The Southern Hub model is likely to enhance the management of system security, by providing financial incentives to market participants to have balanced cumulative supply and demand at times when this is important to the security of the overall system. AEMO, as the system operator, would have the ability to take residual actions to ensure the system remains secure, and the continuous balancing regime that forms part of the Southern Hub model would allow AEMO to take action in a more timely manner than under the current arrangements. In addition, AEMO would retain its existing powers to direct market participants in extreme circumstances to address the most serious or imminent system security issues.

Transition to the Southern Hub model

An advantage of the Southern Hub is that it would provide market participants with greater flexibility in the way they manage their gas requirements. Participants would be able to minimise their exposure to charges that would arise as a result of them being out of balance by any combination of voluntarily trading gas (which can be done on a continuous basis) and adjusting their physical injections or withdrawals.

For participants to have a genuine choice as to how they manage their positions, it is important that gas trading is an attractive option. However, there is a risk that upon introducing the Southern Hub, many market participants – lacking experience with and confidence in hub trading – may initially choose to manage their imbalances entirely by adjusting their injections and withdrawals. This may precipitate a spiral of low liquidity within the hub, as participants collectively lose confidence in the market and seek to retain their flexible gas for their own potential use, instead of risking having to acquire flexible gas on the market. This outcome would diminish many of the key benefits of the reform, and might also mean that gas is not allocated to its highest-valued use.

There may also be some one-off adjustments that market participants will need to make as the Southern Hub is introduced. The existing market provides incentives for participants to inject more gas than they expect to withdraw, to effectively 'self-insure' against the risk and cost of being short. The overall excess of injections has enabled a number of small market participants to source relatively inexpensive gas on the DWGM under certain conditions. The new arrangements may affect the incentives for market participants to be long of gas, and consequently limit small market participants' ability to source cheap gas in the manner to which they have become accustomed, and hence affect the role they play in providing competitive tension to the market.

In the Commission's view, neither of these concerns represent enduring problems with the Southern Hub model. However, transitional measures may be appropriate to stimulate liquidity at the hub and to limit the impact of the changed market design on smaller participants in particular. Over time, once liquidity has been established and market participants have adjusted, the transitional measures would be removed.

Recommendation 4: Market trials should be undertaken to determine the requirement for, and design of, transitional measures that may be appropriate to help stimulate liquidity in the commodity market and mitigate the impacts of changed market arrangements for market participants.

Without prejudging the outcome of these market trials, the Commission considers the following transitional measures would be likely to provide the most benefits on commencement of the Southern Hub model:

- financial tolerances, which would provide (particularly, smaller) market participants with protection against costs that could arise as a result of imbalances between supply and demand; and
- financial incentives for a market participant to be in balance on a daily basis, in order to concentrate liquidity into simple daily or balance-of-day products which market participants would require to remain in balance.

These transitional measures would be expected to stimulate liquidity and provide protection to market participants in adjusting to the new regime. They should also provide a pathway to the implementation of the target model and avoid substantially diminishing the benefits of the target model during the transitional period.

Implementation of the Southern Hub model

There is a need to progress the DWGM reforms in a timely manner, driven by the pace of change in the east coast gas market. By the end of 2018, all six trains associated with the three LNG export projects at Gladstone are expected to be fully operational. One of these projects in particular will be sourcing substantial volumes of gas from outside its portfolio, reducing supply that could have been directed to the domestic market.[8] Over the same period around 450 PJ of long term GSAs are rolling off, requiring domestic customers to enter the market to secure new supply in an uncertain environment.[9]

In August 2016 the COAG Energy Council agreed to establish a time limited Gas Market Reform Group (GMRG) to implement recommendations made by the Commission in its East Coast Review. Dr Michael Vertigan has been appointed to chair the GMRG, being responsible for appointing the project management office and

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

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

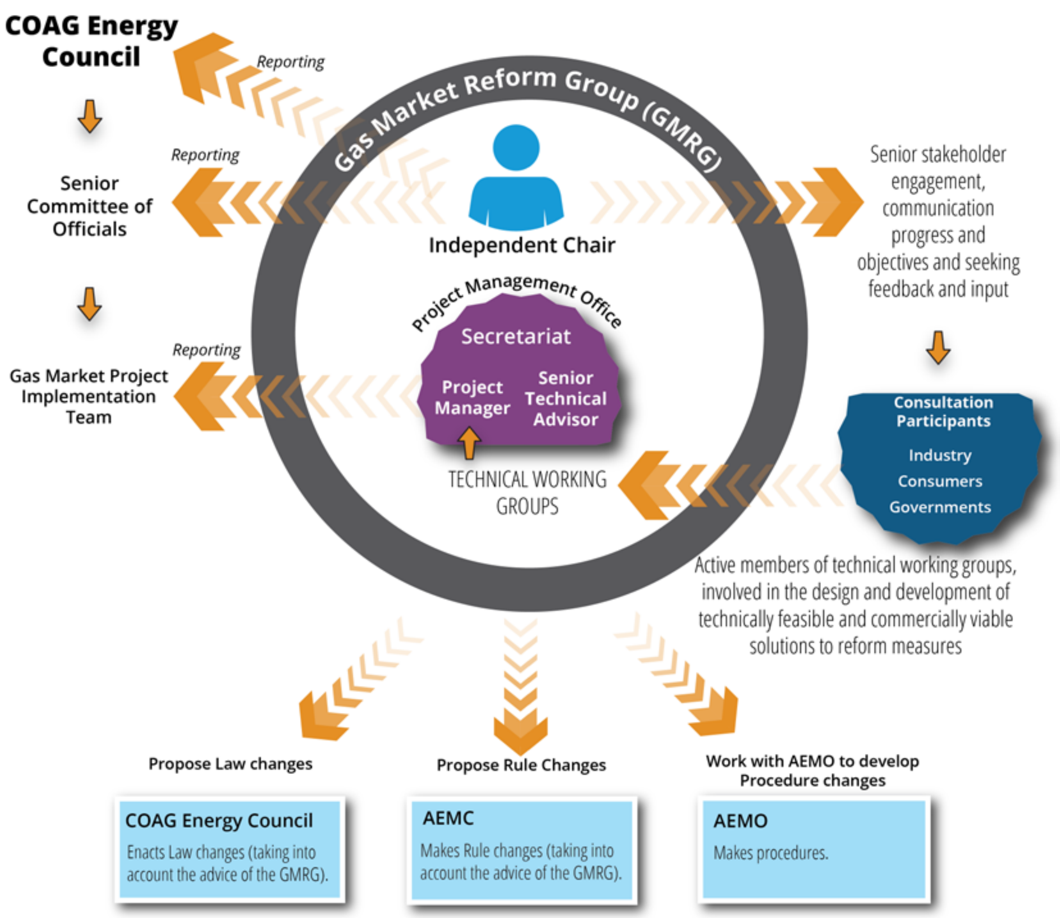
deciding on the form of and terms of reference for technical working groups. It is expected that the GMRG will have been constituted by the end of 2016.

Recommendation 5: The COAG Energy Council should task the Gas Market Reform Group (GMRG) to implement the Commission's recommended reforms to the DWGM (Recommendations 1-4) and the corresponding required design features. The GMRG should also take into account any preferred and suggested elements outlined by the Commission.

The Commission considers the GMRG to be the appropriate body to implement the DWGM reforms recommended in this review. As with the reforms recommended in the East Coast Review, direct industry involvement is required because the reforms are intended to facilitate more efficient commercial transactions of gas and transportation capacity between market participants and are relatively complex.

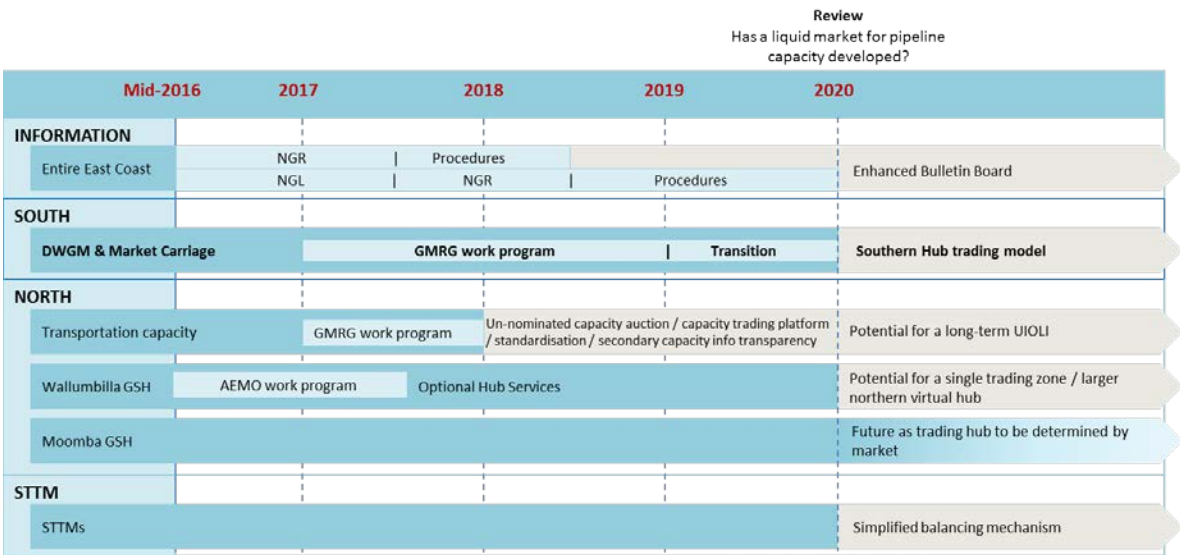
Nevertheless, a substantial degree of involvement is required from policy-makers and regulators through the reform process to ensure that the private interests of industry do not take precedence over the long-term interests of consumers and that the detail of what gets implemented is consistent with the intentions of the Energy Council. Furthermore, given the interconnected nature of the east coast gas markets, there is a risk of poor coordination between the DWGM reforms and the reforms recommended in the East Coast Review if an alternative approach is used.

Figure 1 Gas Market Reform Group implementation



The Commission has identified various outcomes related to each of the recommendations in this report. Where the Commission considers that a particular recommendation is necessary for the overall reform to be effective, this has been reflected as a **required** outcome and the GMRG should be tasked by the COAG Energy Council to further develop the package of regulatory changes which delivers it. The GMRG should pursue **preferred** outcomes unless it is clear that there are greater benefits in alternative approaches and **suggested** outcomes given the in-principle benefits that may arise from their implementation.

Figure 2 Timeline for reforms



Recommendations

1. **Recommendation 1**: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.

2. **Recommendation 2:** Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.

3. **Recommendation 3:** The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.

4. **Recommendation 4:** Market trials should be undertaken to determine the requirement for, and design of, transitional measures that may be appropriate to help stimulate liquidity in the commodity market and mitigate the impacts of changed market arrangements for market participants.

5. **Recommendation 5:** The COAG Energy Council should task the Gas Market Reform Group (GMRG) to implement the Commission's recommended reforms to the DWGM (Recommendations 1-4) and the corresponding required design features. The GMRG should also take into account any preferred and suggested elements outlined by the Commission.

A full list of the required, preferred and suggested features of these recommendations is provided in Appendix D.

Contents

1 Introduction

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

This process has been accelerated by the commencement of liquefied natural gas (LNG) exports from Queensland, which has driven an increase in overall gas demand, the development of new sources of supply and introduced new pricing structures. The shifts in supply and demand, and consequential changes in patterns of gas flows, are impacting market participants and consumers across the east coast, including in facilitated markets such as the Victorian declared wholesale gas market (DWGM). These factors have led to a renewed focus on market development and supply chain efficiency.

Against this background, the Council of Australian Governments (COAG) Energy Council, at the request of the Victorian Government, has asked the Australian Energy Market Commission (AEMC or Commission) to undertake a detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the DWGM (the DWGM Review).[10]

Concurrently, the COAG Energy Council also requested that the AEMC undertake a broader review of the design, function and roles of facilitated gas markets and gas transportation arrangements across the Australian east coast (the East Coast Review).[11]

1.1 Review process

The East Coast and DWGM Reviews have been structured over two stages. The reviews were carried out together in Stage 1 and then split into two separate reviews at the commencement of Stage 2.

The Commission completed Stage 2 of the East Coast Review in May 2016, with the Stage 2 Final Report being published on 28 July 2016.[12] In the report, the Commission set out a roadmap for gas market development on the east coast of Australia. A key feature of the roadmap is the Commission's recommendation that wholesale gas market trading should be concentrated at two points:

- a Northern Hub, based around the existing Gas Supply Hub at Wallumbilla, Queensland; and
- a Southern Hub, which would be established by enhancing the existing DWGM in Victoria.

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

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

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

The Commission also made a number of other recommendations in the Stage 2 Final Report targeted at improving secondary capacity trading on pipelines outside of Victoria and enhancing the information provided to the market through the Natural Gas Services Bulletin Board.[13] The Commission further recommended the establishment of an independent, dedicated group to implement many of the reforms.

The Stage 2 Final Report was considered by the COAG Energy Council at its meeting on 19 August 2016. The Council, in large part, accepted the Commission's recommendations, and constituted the Gas Market Reform Group (to be chaired by Dr Michael Vertigan) as the implementation body for the Council's Gas Market Reform Package. Of particular note for the DWGM Review was the Council's decision to give in-principle support for the establishment of the Southern Hub by transitioning the existing DWGM to the Commission's recommended design, subject to the Final Report of the DWGM Review.

This report forms the Draft Final Report for the DWGM Review. It is being published for consultation prior to the submission of the Final Report to the COAG Energy Council and the Victorian Government.

The key milestones for both the East Coast and DWGM Reviews are set out in Table 1.1 below.

Table 1.1 Review process

Date	Milestone	
	East Coast Review	**DWGM Review**
20 February 2015	Terms of Reference	
25 February 2015	Public Forum and Discussion Paper	
4 March 2015		Terms of Reference
7 May 2015	Stage 1 Draft Report	
23 July 2015	Stage 1 Final Report	
6 August 2015	Wholesale Gas Markets Discussion Paper	
10 September 2015		DWGM Discussion Paper
18 September 2015	Pipeline Regulation and Capacity Trading Discussion Paper	
30 September 2015	Public Forum	

13 This followed four earlier recommendations for immediate action set out in the Stage 1 Final Report and agreed to by the Council at its meeting on 23 July 2015.

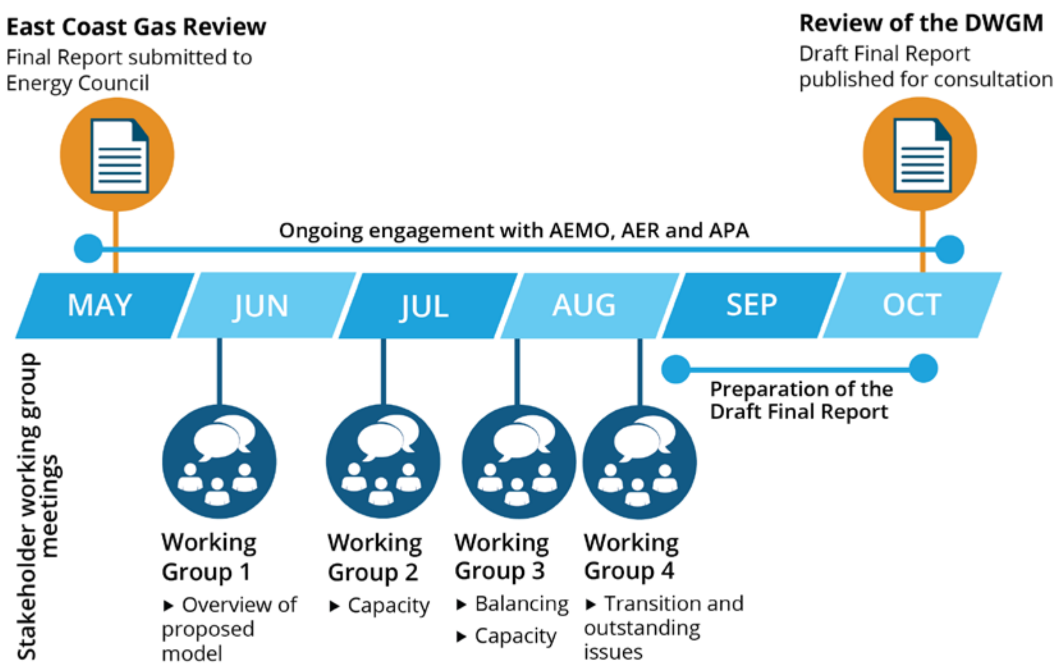
Date	Milestone	
4 December 2015	Stage 2 Draft Report	DWGM Draft Report
3 March 2016	Pipeline Access Discussion Paper	DWGM Supplementary Discussion Paper
13 May 2016		DWGM Review Extension
23 May 2016	Stage 2 Final Report	
14 October 2016		DWGM Draft Final Report
TBC		DWGM Final Report

1.1.1 DWGM Review Working Group

On 13 May 2016, the Victorian Government extended the timeframes for the DWGM Review to allow for further consultation and detailed analysis of the issues. It specified that a Draft Final Report be provided by 14 October 2016 and subsequently published for consultation prior to the Final Report being released.

To facilitate further consultation, the AEMC established a working group of interested Victorian market participants. We also held bilateral discussions with many stakeholders, including workshops with AEMO, AER and APA on the details of the reforms.

Figure 1.1 Consultation timeline



Four working group meetings were held over June to August 2016. These meetings were well attended by industry members and included representatives from: market bodies; retailers; gas fired power generators; pipeline owners; large customers; and consumer representatives.

The working group meetings were used to identify and work through issues identified by stakeholders to make sure there were no 'showstoppers' and that issues were at least resolvable. The meetings were also used to educate and inform market participants on the detail of various aspects of the Southern Hub model.

For example, as a result of issues raised during discussion on 'balancing', the AEMC carried out additional work on transitional arrangements that could address those concerns (see Chapter 7).

The meeting dates and topics are set out in Table 1.2 below.

Table 1.2 Working group meetings

Date	Topics covered
15 June 2016	Overview of the proposed model
13 July 2016	Capacity
10 August 2016	Balancing Capacity (follow up)
31 August 2016	Recap of the proposed model Transitional arrangements

The Commission thanks the working group participants for their engagement and valuable input to this review. Material and outcomes from these meetings are available on the AEMC's website.

1.1.2 Advisory Group

As required by the terms of reference, the Commission established an Advisory Group that operated across the East Coast and DWGM Reviews. This group was used to provide strategic advice and expertise to the Commission over the course of the review. It met periodically and was chaired by John Pierce, AEMC Chairman. Advisory Group member organisations are listed in Table 1.3.

The Advisory Group met to discuss the DWGM Draft Final Report on 21 September 2016.

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

Table 1.3 Advisory Group Members

Member	Role
Australian Energy Market Operator	Market operator
APA	Pipeline owner
Jemena	Pipeline owner and distributer
Australian Pipeline and Gas Association	Pipeline association
Santos	Producer
ExxonMobil	Producer
Origin Energy	Producer, retailer and gas fired power generator
AGL Energy	Producer, retailer and gas fired power generator
Energy Australia	Retailer and gas fired power generator
Simply Energy (Engie)	Retailer (small) and gas fired power generator
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)

1.2 Structure of this Draft Final Report

This is the Draft Final Report of the DWGM Review. The remainder of this document is structured as follows:

- Chapter 2 provides an overview of the structural changes affecting the DWGM, assesses the DWGM against the objectives guiding this review and identifies the issues with the current market arrangements inconsistent with the achievement of these objectives;
- Chapter 3 outlines the Commission's recommended package of reforms and their benefits, and describes how they should be progressed;
- Chapters 4 to 6 provide an overview of the Commission's recommendations with regard to the "target model" for trading at the Southern Hub on the topics of

commodity trading, balancing and capacity allocation respectively. The target model represents the final design for the Southern Hub; and

- Chapter 7 discusses the Commission's recommendations for arrangements to smooth the transition to the "target model", recognising the potential need for interim market design features to address specific stakeholder concerns.

The Draft Final Report also contains a number of appendices, including:

- Appendix A: Terms of reference;
- Appendix B: Assessment framework;
- Appendix C: Responses to questions posed by the Victorian Government; and
- Appendix D: Table of required, preferred and suggested features of the Commission's recommendations.

A separate technical report that provides a more detailed description of the Southern Hub model and the rationale for many of the design choices made accompanies this Draft Final Report and can be found on the AEMC's website.

1.3 Responding to this Draft Final Report

The Commission welcomes responses on the proposed changes to the Victorian DWGM outlined in this Draft Final Report. Any feedback received from stakeholders will be used to inform the Commission's final recommendations for the DWGM Review to be presented to the COAG Energy Council and published in the final report.

Submissions on this Draft Final Report are due no later than Friday 2 December 2016.

Submissions should refer to the AEMC project number "GPR0002" and be sent electronically through the AEMC's online lodgement facility at www.aemc.gov.au.

All submissions received will be published on the AEMC's website, subject to any claims for confidentiality.

2 Meeting the Vision

Box 2.1 Summary of chapter

The Declared Wholesale Gas Market (DWGM) was established in 1999 by the Victorian government, with the objective of supporting retail competition and encouraging diversity of supply and upstream competition. Today, it provides an effective gas balancing service and facilitates a limited amount of trading of gas based on short-term prices.

However, developments in the wider east coast market are now presenting new challenges and exacerbating known issues in the current DWGM market design.

The large and emerging liquefied natural gas export industry in Queensland has put upward pressure on domestic prices and increased their volatility. This is a consequence of two factors. First, LNG exports have created a nexus between domestic gas prices and higher and more volatile international gas prices. Second, unexpected changes in demand from the LNG industry have the potential to create volatility in the demand for – and hence flows of – domestically-produced gas, with consequential impacts on prices. These trends look set to continue and strengthen over time.

These changes come at a time when many long-term gas supply agreements are expiring, with new agreements offered with greater restrictions on the ability of market participants to manage risks associated with price and volume volatility.

The Victorian gas industry is subject to the same market forces as the rest of the east coast gas market through the interconnected transmission pipeline network that spans eastern Australia. Managing emerging risks presents both potential opportunities and costs for Victorian market participants.

Recognising these changes, the Council of Australian Governments (COAG) Energy Council formulated a Vision for Australia's future gas market, encompassing the key themes of effective risk management, transparency in pricing, market-driven investment and effective trading between hubs.

However, the existing DWGM does not facilitate the achievement of the Vision, in large part due to features inherent to its design:

- As an alternative to managing risk through gas supply agreements, a financial derivatives market has not emerged as a side market to the DWGM because of the complexity of the DWGM's design.
- Current market arrangements are unable to deliver a meaningful, market-based reference price for gas that reflects underlying supply and demand condition in both the short and long term.
- The regulatory framework for the declared transmission system (DTS) does not encourage market-driven investment. Consequently, investment decisions in the DTS generally result from a regulatory process, with the costs and risks borne by consumers.

- The DWGM has significantly different market arrangements and trading platforms to other facilitated gas markets on the east coast. The disjointed nature of the various market designs does not facilitate trade between hubs.

2.1 Impacts of the east coast gas market transformation on the DWGM

The DWGM is the longest-standing facilitated wholesale gas market in Australia, encompassing the entire declared transmission system (DTS). As illustrated in Figure 2.1, the DWGM is connected to the rest of the east coast gas market, including the large liquefied natural gas (LNG) export facilities in Queensland, through a number of interconnected transmission pipelines. The figure shows how the DTS comprises of pipelines extending from Longford in Gippsland in the east of Victoria, across to Portland in the south west, through central Victoria and north to Albury/Wodonga and Culcairn in New South Wales. Other transmission pipelines link the DTS to South Australia (SEA Gas) and the New South Wales south coast (Eastern Gas Pipeline). A more detailed map of the DTS is provided in Chapter 1 of the Technical Report.

Figure 2.1 The DTS as part of the east coast gas network

Preceding all three short-term trading market (STTM) hubs and the recently implemented gas supply hub (GSH) model, the DWGM is the only virtual hub on the east coast of Australia.[14]

The DWGM was established in 1999 by the Victorian government with the objective of supporting retail competition and encouraging diversity of supply and upstream competition. Today, the DWGM provides an effective gas balancing service and facilitates a limited amount of trading of gas based on short-term prices.

Retail competition in the DWGM has high customer activity and relatively low market concentration. While no new retailers entered the market in 2016, two new retailers entered the market in 2015, bringing the total number to ten. Data available on switching also suggests customers are actively shopping around between retailers.[15]

However, developments in the wider east coast market are now presenting new challenges and exacerbating known issues in the current DWGM market design.

Between 2014 and 2016, gas demand on the east coast will have increased threefold, driven by LNG exports.[16] This substantial increase in demand has put upward pressure on domestic gas prices. With the first LNG cargoes exported from Gladstone in January 2015, the domestic market is already feeling the effects of greater competition for gas.

Exposure to international LNG prices has increased not only the level, but also the volatility, of domestic gas prices.[17] As many export contracts are linked to international oil prices, there has been a growing trend to link domestic gas prices to oil, presenting a new and unfamiliar risk for all gas buyers to manage.[18] In addition, there is an inherent variability in coal seam gas (CSG) supply, which has in recent years become a significant source of gas and is a key supplier of the LNG industry. The variability of CSG supply has further exacerbated overall gas price volatility.[19]

Another potential source of increased volatility arises from the operating characteristics of the LNG export industry. In particular, operational incidents relating to the LNG supply chain have the potential to create very large changes in the flows of gas across the east coast. For example, an unexpected shutdown of an LNG processing facility or related infrastructure, or the delay of the arrival of a scheduled LNG export

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14 A gas hub is a location where the transfer of ownership and pricing of physical gas takes place. At physical hubs, this occurs at a specific location on the pipeline system, while virtual hubs typically encompass a large segment, or all, of a pipeline system.

15 AEMC, *2015 Retail Competition Review*, 30 June 2015, p. 150. AEMC, *2016 Retail Competition Review*, 30 June 2016, p. 6.

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

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

18 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, July 2016, pp. 21-22; ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 31-32, 36.

19 Australian east coast coal seam gas production nearly quadrupled in the last four years, from 247PJ in the 12 months to June 2012 to 933PJ in the 12 months to June 2016. This represents an increase from 35 per cent to 67 per cent of total east coast gas production. EnergyQuest, *Quarterly August 2016 Report*, pp. 77, 103; EnergyQuest, *Energy Quarterly August 2014 Report*, pp. 64, 85; EnergyQuest, *Energy Quarterly August 2013 Report*, pp. 62, 81.

carrier, could result in a large quantity of gas (of an order of magnitude similar to total east coast Australian domestic demand) suddenly being made available to the domestic market, with CSG wells having only a limited ability to reduce supply in these instances.[20] These incidents are likely to create price volatility across eastern Australia, presenting both downside and upside risks to market participants.

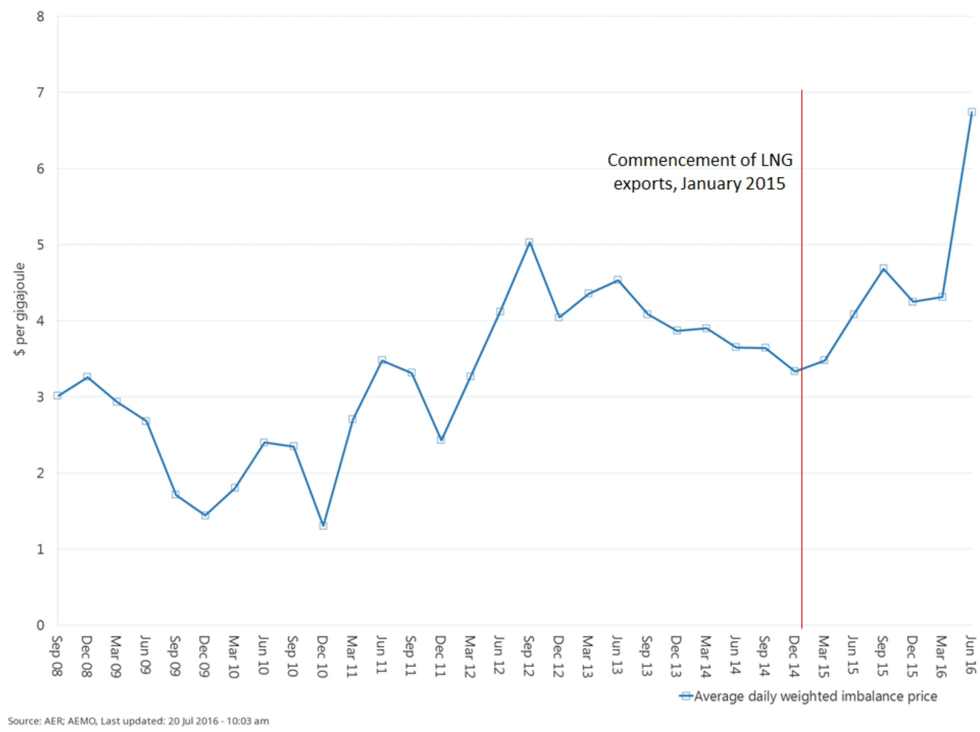
Connected to the rest of the east coast gas market (and ultimately the international market) through interconnected transmission pipelines, the Victorian gas industry is subject to these market forces. The changes to the supply and demand dynamics on the east coast are expected to significantly affect the DWGM in two ways, namely:

1. Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with other end users in these states likely to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect, the Eastern Gas Pipeline or the SEA Gas Pipeline.

2. Equally, market participants may seek to transport large volumes of gas into Victoria for sale in the DWGM where the LNG export plants are unable to absorb supply due to the factors described above.

The effect of the LNG industry on Victorian gas prices is already being observed. Quarterly average daily DWGM prices are at a historic high at $6.74 per GJ in the second quarter of 2016.This has nearly doubled in the last eighteen months, as illustrated in Figure 2.2.[21]

Figure 2.2 Price increases in the DWGM

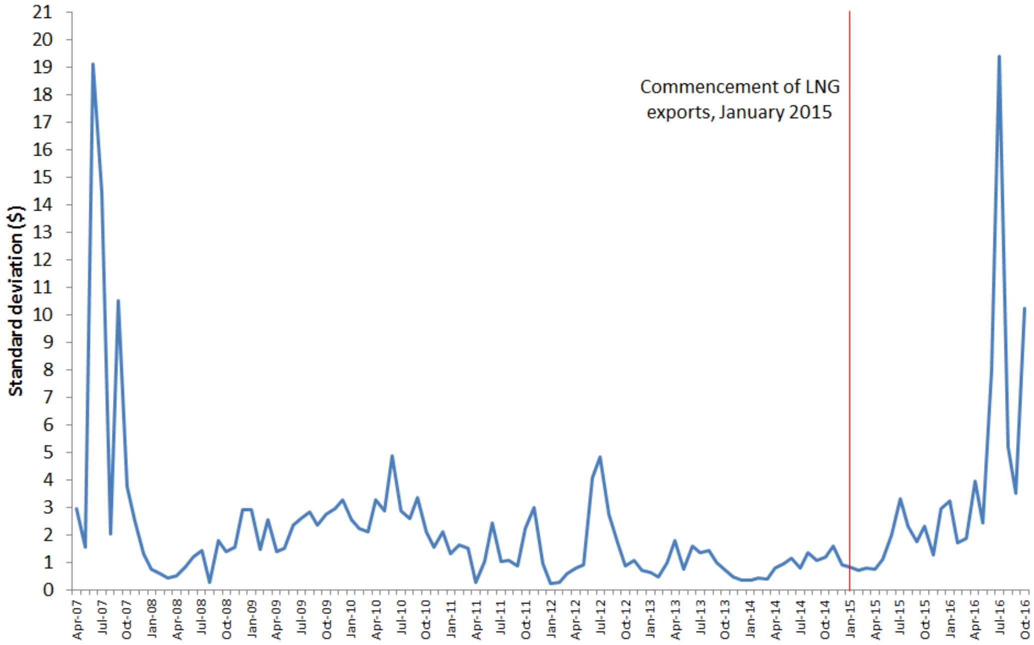


20 PwC estimates the number of shutdowns of LNG processing facilities could be in the range of zero to ten days per year. PwC, *Cost benefit analysis of gas market reforms*, May 2016, p. 54.

21 AER Wholesale Statistics, available at: http://www.aer.gov.au/wholesale-markets/wholesale-statistics/victorian-gas-market-average-daily-weighted-prices-by-quarter.

In addition to increases in the level of prices, the market has also experienced increased price volatility. High price volatility is an important consideration because it tends to increase market participants' exposure to financial risk. Figure 2.3 shows an increase in the variability of prices in the DWGM starting from approximately the time of the first LNG export in January 2015.[22]

Figure 2.3 Price variability in the DWGM beginning of day 6am gas price



As the Queensland LNG industry reaches and maintains full production by 2018, there is likely to be further and sustained increases in the level and volatility of domestic prices.

The transition in the sector has coincided with the expiry of many domestic long-term gas supply agreements (GSAs),[23] raising questions around the DWGM's resilience to such significant changes. Market participants now require greater flexibility in how they buy and sell gas outside of bilateral gas contracts and new approaches to risk management.[24] The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed.

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22 The variability in prices was also high in 2007. The Commission understand that this was a consequence of changes to the market design in February 2007 from *ex post* daily pricing to *ex ante* intra-day pricing. The standard deviation in Figure 2.3 is calculated as:

$$\sigma = \sqrt{\frac{\sum_{t=1}^{N_t}(\Delta p_t - \Delta\bar{p})^2}{N_t - 1}}, \; N_t = 7$$

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

24 While customers connected to the DTS have to purchase gas through the DWGM, most retailers and some large customers would have long term GSAs which they offer into the market.

Box 2.2 Risk management strategies are becoming more important

More flexible and sophisticated means of managing gas portfolios are becoming increasingly important to market participants for the following reasons:[25]

- GSA contract prices are rising due to the **tightening of the supply and demand balance**. While this should incentivise more supply into the market, restrictions and inquiries into gas field exploration and development in several jurisdictions have been inhibiting this response.[26] As a consequence, participants are seeking to source sufficient gas to meet their demand and reduce their average gas supply costs through market-based trading.
- GSAs now tend to have more **restrictive terms and conditions (reduced flexibility)**, in particular with reduced load factor flexibility and/or increases in the cost of flexibility.[27] This may be due to producers seeking to run their facilities at higher capacity to take advantage of increased demand on the east coast, while offering flexibility in GSA's can result in underutilisation of the facility outside peak periods. This is incentivising participants to utilise trading markets to procure flexibility.
- Exposure to international LNG and oil prices has **increased spot price volatility**. Price volatility is likely to provide participants with commercial opportunities to arbitrage gas prices between trading markets on the east coast, or between their bilateral contract price and the spot price. It also makes it increasingly important that participants have the ability to manage the increased price risks on trading markets.

While the DWGM and associated market carriage transportation arrangements[28] are generally considered to have been providing an effective gas balancing service and facilitating some gas trading in Victoria historically, market participants are unable to insulate themselves from the effects of supply and demand changes across the wider east coast.

With potentially large and unpredictable amounts of gas being injected into or withdrawn from the DWGM, it is critical that the Victorian gas market design is sufficiently flexible to accommodate a range of potential scenarios for gas flows and that participants are able to actively manage the risks they face. Ministers at the July 2015 Energy Council meeting noted the "new era of dynamism" in the gas market, and emphasised "the imperative... to get the fundamentals right to prepare market

25 A more detailed description of these issues is provided in: AEMC 2016, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 Final Report, 23 May 2016, pp. 3-8.

26 ACCC, *Inquiry into the east coast gas markets*, April 2016, pp. 65-66.

27 ACCC, *Inquiry into the east coast gas markets*, April 2016, p. 71.

28 The market carriage model, which provides open access to the DTS uses outcomes from the operation of the DWGM to schedule injections and withdrawals from the pipeline.

participants for new ways of price discovery, trading, investment and risk management".[29]

2.2 A vision for future gas markets

In light of the above changes, the Council of Australian Governments (COAG) Energy Council formulated a Vision for Australia's future gas market. Released in December 2014, the Vision is as follows:[30]

> "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."

At the present time, gas market arrangements across the east coast of Australia are not consistent with the COAG Energy Council's Vision. The work of the Commission through the DWGM review, as well as the East Coast Review, has been to develop a roadmap for gas market development that allows the Vision to be met.

The Vision provides a high level policy statement that has guided the analysis undertaken in this review, focused on key outcomes for the gas market that are necessary to meet the National Gas Objective (Box 2.3).

The achievement of the Vision is an important objective given the changes occurring in the gas market and the limitations of the current market arrangements to accommodate these changes, which are discussed in sections 2.3 and 2.4 of this report. The COAG Energy Council's Vision can be broken into three key outcomes:

1. Establishment of a liquid wholesale gas market and, consequently, an efficient and transparent reference price for gas that provides market signals for investment and supply.

2. A supportive regulatory framework for investment that facilitates responses to these market signals.

3. Market arrangements that allow participants to readily trade gas between hub locations.

29 COAG, Energy Council Meeting Communique, 23 July 2015, p. 2.

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

Box 2.3 The National Gas Objective

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

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

The NGO is structured to encourage energy market development in a way that supports the:[31]

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

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

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

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

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

2.2.1 The DWGM review terms of reference

The outcomes of the COAG Energy Council's Vision are broadly the subject of the Victorian Government's terms of reference for the DWGM review,[32] which 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

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

32 See Appendix A.

promote competition in upstream and downstream markets, in the long-term interest of consumers."

Consistent with this terms of reference, the DWGM review is examining and seeking to achieve the following attributes:

- Effective risk management in the DWGM: whether market participants are able to manage price and volume risk and options to improve the effectiveness of risk management activities.
- Signals and incentives for efficient investment in and use of pipeline capacity: whether investment in the DTS will occur in an efficient and timely manner and options to strengthen the signals and incentives for efficient investment.
- Trading between the DWGM and interconnected pipelines: whether the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines, and options to allow producers and shippers to effectively operate across gas trading hubs on the east coast without incurring substantial transaction costs.
- Promoting competition in upstream and downstream markets: whether the DWGM continues to encourage the introduction of new gas supplies to the market and promote competition among retailers for the sale of gas, and the extent to which the design of the DWGM may be a deterrent to large users participating in the market.

2.2.2 The DWGM does not facilitate the achievement of the Vision

By drawing upon the key elements of the Vision and, particularly, those attributes highlighted in the terms of reference for the review, the Commission has identified a number of objectives to guide the development of the DWGM. As outlined in Table 2.1, these objectives are not met by the current DWGM arrangements. Consequently, the Commission considers the DWGM will not facilitate the achievement of the Energy Council's Vision for Australia's future gas market.

Table 2.1 DWGM and the Vision

Market development objective	Whether supported by the DWGM
Improved ability for market participants to manage price and volume risk.	× As a spot-market, market participants are unable to manage price and volume risk through the DWGM itself. The complexity of the DWGM has not been conducive to the development of a liquid financial derivatives market as an alternative "side market" to the DWGM, through which market participants would be provided an alternative to manage price and volume risk.

Market development objective	Whether supported by the DWGM
An efficient and transparent reference price for gas that provides market signals for investment and supply.	× Current market arrangements are unable to deliver a meaningful, market-based reference price for natural gas which reflects underlying supply and demand condition in both the short and long term. While the DWGM spot price reflects immediate supply and demand conditions, it is not representative of the longer term. Long term trades (such as GSAs) are negotiated bilaterally, with the terms and price kept confidential.
A supportive regulatory framework for investment that facilitates responses to market signals.	× The regulatory framework for the DTS does not encourage market-driven investment. Consequently, investment decisions in the DTS generally result from a regulatory process, with the costs and risks borne by consumers.
Market arrangements that allow participants to readily trade gas between hub locations.	× The DWGM has significantly different market arrangements and trading platforms to other facilitated gas markets in eastern Australia. The disjointed nature of the various market designs does not facilitate trade between locations.

2.3 Overview of the current DWGM design

This section provides a brief description of the design features of the current DWGM, with a focus on those features which are limiting its ability to facilitate the Vision. A more comprehensive description of the current DWGM can be found in Stage 1 of the AEMC's Wholesale Gas Market and Pipeline Frameworks Review.[33] Section 2.4 then provides an explanation of why the DWGM is limited in its ability to facilitate the Vision.

The DWGM can be considered to integrate three roles into one:

- trading of gas on the gas day;
- managing system-wide balancing; and
- managing gas flows on the DTS consistent with its physical capacity.

These points are discussed below.

33 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, Chapter 6 and Appendix F.

2.3.1 Gas trading

The DWGM facilitates the trading of gas between market participants. Each market participant is required to submit price/quantity pairs of bids and offers into the DWGM in order to inject or withdraw gas from the DTS for the remainder of the gas day.[34] Based on bids and offers and subject to the pipeline system security limits, AEMO's market clearing algorithm schedules each market participant's injections and withdrawals by minimising the cost of supplying demand.[35]

Market participants who are scheduled to withdraw more than they are scheduled to inject (i.e. are net short) pay the market price on the quantity of gas they are short. Conversely, market participants who are scheduled to inject more than they are scheduled to withdraw (i.e. are net long) receive a payment of the market price on the quantity of gas they are long. These payments are known as "imbalance payments", and in effect are payments for the trade of gas between market participants.[36]

The market price used to settle imbalance payments is set *ex ante* (i.e. based on the schedule of gas flows, not on the actual gas flows) and at the price of the most expensive unit of gas that would have been scheduled absent of any physical constraints on the system.

The DWGM can be considered a form of "virtual" gas hub. Market participants are required to inject and withdraw gas to and from the DTS when scheduled, but it is AEMO which is responsible for the delivery of gas across the DTS. Market participants are not required to transport gas to and from a specific physical point in the DTS in order to trade. Any trading of gas therefore occurs nowhere in particular within the DTS – gas purchases are simply net withdraws from the virtual hub, and gas sales are net injections to the virtual hub.

The DWGM scheduling process occurs regularly at five pre-defined times within the gas day.[37] For the first schedule of the day, at 6.00am, gas is scheduled for the entirety of the upcoming gas day. Each subsequent scheduling process then revises the schedules for the balance of the gas day, with a new market price set for each schedule. This therefore allows for the trading of gas through the DWGM for the upcoming gas day or for the balance of the gas day.

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34 More precisely, market participants do not need to bid gas for uncontrollable withdrawals such as for household consumption. Instead, a forecast of uncontrollable demand is automatically "bid" into the DWGM at the market price cap and scheduled.

35 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, p. 34.

36 "Imbalances" in the DWGM therefore refer to the difference between a market participant's scheduled injections and scheduled withdrawals, and hence result in trades with another market participant. The overall system is not out of balance as a result of trades.

37 Ad-hoc schedules may also occur but only if there are impending or imminent threats to system security requiring urgent action.

2.3.2 Managing system balancing

Where market participants fail to meet their scheduled injections and withdrawals, system linepack will increase or decrease to a greater or lesser extent than anticipated, and the system as a whole will become out of balance.

These system imbalances are also managed by AEMO through the DWGM scheduling process. In such circumstances, AEMO buys or sells gas in the next schedule (at the next schedule's market price) in order to manage linepack variations in the preceding schedule, with the intention of meeting an end of day linepack target.

AEMO's costs or proceeds from the trades are mostly recovered through payments made by or to market participants who deviate from their schedule, commensurate with the impact the market participants had on the system. The payments made by or to deviating parties are consequently known as deviation payments.

Deviation payments are settled at the *ex pos*t price (i.e. at the market price of the next schedule) because AEMO is buying or selling gas in the next scheduling horizon. This contrasts to imbalance payments, which are settled at the *ex ante* price (i.e. at the market price of the current schedule).[38]

2.3.3 Managing the flow of gas consistent with its physical capacity

As the DWGM is a virtual gas hub, it is AEMO's responsibility to manage capacity constraints on the DTS to ensure the physical delivery of gas from injection to withdrawal points, and this is also done through the DWGM scheduling process.

In order for a market participant to inject gas into or withdraw gas from the DTS for the upcoming or current gas day, it is mandatory for it to offer all of its gas into the DWGM and bid to take gas out the DWGM.[39] That is, market participants must bid/offer their gross position in order to be scheduled and gain access from/to the DTS.

Market participants are required to do this as, in the event of a constraint, it provides AEMO's market clearing algorithm the information it needs to determine the lowest cost combination of gas to schedule to meet demand, subject to the constraint.[40] As

38 To be clear, deviation payments are made on deviations between scheduled injections and withdrawals, and actual injections and withdrawals, and are settled *ex post*; imbalance payments are made on imbalances between scheduled injections and scheduled withdrawals, and are settled *ex ante*.

39 In the DWGM, offers to sell gas are known as "injection bids" and bids to buy gas are known as "withdrawal bids". This report will use the term "offers" and "bids" respectively.

40 Strictly, the algorithm determines the lowest *priced* combination of gas to schedule to meet demand, based on market participants' offers. Assuming market participant's offers accurately reflect their costs, then the algorithm efficiently schedules the lowest cost combination.

such, access to the DTS is determined through the DWGM, and so the capacity arrangements are known as "market carriage".[41]

In this way, the allocation of capacity through the DWGM and the requirement to bid and offer all gas for the day are intrinsically linked design features.

In the event of a physical constraint, market participants can be constrained off and not scheduled to inject despite offering gas below the market price. Necessarily, other market participants are constrained on, and are scheduled to inject despite offering gas above the market price.

In the event that two market participants offer or bid gas at the same price but both cannot be scheduled due to a physical constraint, those holding AMDQ rights (explained in Box 2.4) will be scheduled ahead of those without. In this way, AMDQ offers limited protection from the risk of being constrained off. The amount of available AMDQ rights is set with regard to the physical capacity of the system.

Box 2.4 Authorised Maximum Daily Quantity

In the event of a constraint, market participants which are holders of Authorised Maximum Daily Quantity (AMDQ) or AMDQ credit certificates (AMDQ cc) (collectively commonly referred to as AMDQ) are provided financial rights and limited rights to physically access the DTS.[42]

AMDQ was first allocated at market start and was (and has remained) aligned with the capacity of the Longford-Melbourne pipeline at that time when it was the sole source of gas supply for the DWGM.

The DTS has been expanded and extended since 2008 and the new pipeline capacity has been allocated as AMDQ cc to provide similar benefits to those arising from AMDQ on the Longford pipeline.

As noted in section 2.3.1, the market price is determined assuming no constraints on the system. In the event of a constraint on the system, an ancillary payment is used to compensate a market participant that is constrained on, so that in total, the market price plus the ancillary payment equals its offered price for the gas it injects. Absent of ancillary payments, market participants would receive less than their offered price.

Ancillary payments to constrained on market participants are funded through uplift payments, which, to the extent possible, are charged to parties whose actions cause the ancillary payments, whether that is market participants or the DTS service provider (APA). There are three types of uplift payments which a market participant can be subject to:

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41 This contrasts with "contract carriage" for access to transmission pipelines in eastern Australia outside of the DTS. Under contract carriage arrangements, access is provided to a shipper through a contract with a pipeline owner.

42 A more detailed description of AMDQ and AMDQ cc is provided in: *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, Appendix F.

- congestion uplift;
- surprise uplift; and
- common uplift.

When the system is constrained such that ancillary payments are required:

- **Congestion uplift** charges are levied on market participants who are scheduled to withdraw in excess of their allocated portion of the physical capacity of the system, as defined by their Authorised Maximum Interval Quantity (AMIQ) (derived from the AMDQ). AMDQ therefore provides financial protection against congestion uplift, but this protection is limited because it is not granted if a participant is not injecting gas.

- **Surprise uplift** charges are levied against market participants whose unexpected actions contribute to the constraint (for example by injecting or withdrawing other than their scheduled quantities, or changing their demand forecast), and hence contribute to the need for higher cost gas to be scheduled.[43] Surprise uplift cannot be hedged, but can be mitigated against through accurate forecasting by market participants.

- **Common uplift** charges are uplift charges that cannot be allocated to any market participants via congestion or surprise uplift.[44] Clearly, this risk cannot be mitigated nor hedged by market participants.

2.4 Emerging issues resulting from the DWGM design

As noted in section 2.1, the east coast gas market is undergoing significant changes, which present new challenges for the DWGM and exacerbate pre-existing concerns regarding the market design.

The Commission has identified four key areas of concern with the existing DWGM arrangements that limit its ability to facilitate the Vision:

- an inability to effectively manage risk, which is now particularly important in light of recent and likely future increased volatility in gas flows and prices;

43 If injections, withdrawals or demand unexpectedly change, then more expensive but closer and more timely gas (e.g. from the Dandenong liquefied natural gas facility) may need to be scheduled (constrained on) instead of cheaper but more distant gas (e.g. at Longford).

44 For example, costs associated with any excessive AEMO demand forecast overrides. 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, pp. 45, 86.

- a lack of transparent and meaningful reference prices, which are important to aid effective short and long term decision-making across the gas supply chain in operations, investment, production and consumption; and
- a regulatory framework which does not facilitate market-driven investment in the DTS and instead allocates the risk of network investment decisions to consumers; and
- trading between hub locations may be inhibited by the significant differences between the DWGM's design and the design of other facilitated gas markets in eastern Australia.

As described below, the first three of these issues arise from the bundling of capacity management and balancing into the commodity trading process, and are therefore intrinsic to the DWGM's existing design. The last of these issues is a result of the contrast between the design of the DWGM and the design of other eastern Australian facilitated gas markets.

2.4.1 Inability to effectively manage risk

Managing the risk of variations in price

Due to the factors highlighted in the previous section, gas prices across eastern Australia have become more volatile than they have been historically, as shown by Figure 2.3. This volatility is likely to become even more pronounced as more LNG facilities are commissioned.

Efficient markets tend to allow participants to manage the financial risks which arise when they have a short or long position in the market.

One way to manage a short position in a gas market would be to purchase gas for delivery into the future, but agree the price with the counterparty today. As gas is delivered on future dates, the market participant's requirements will have already been met, and the market participant will not be required to buy or sell additional gas on the spot market at a price which is unknown today. This is known as a physical position.

As a core design feature, the products sold on the DWGM are only a day ahead/balance of day product - i.e. the DWGM is a spot market. There is no way, *within the DWGM itself,* to enter into a physical position.

Instead, market participants are currently able to manage spot price risk by entering into Gas Supply Agreements (GSAs) outside of the DWGM, for example with producers at injection points to the DTS.[45] These contracts are physical positions, in that they allow counterparties to agree the delivery of gas at a future date at a price agreed today. Approximately 80 per cent of trading takes place outside of the DWGM

45 Market participants can also naturally hedge by becoming vertically integrated (i.e. producing and supplying their own gas to meet their portfolio of demand).

in this way, and has led to most participants aligning their bids and offers in the DWGM to the terms of their GSAs.[46] By offering gas purchased through a GSA into the DWGM at a very low price (typically the market floor price ($0/GJ)) to meet their own demand (which is typically bid out of the DWGM at the market price cap ($800/GJ)), market participants are in balance and hence not exposed to the DWGM market price.

However, GSAs appear increasingly insufficient as a tool for market participants to balance their gas supply and demand requirements in order to manage exposure to the DWGM market price. As noted in section 2.1, GSAs that are now being offered by producers tend to have more restrictive and more expensive load factor flexibility than historically (i.e. market participants are less able to vary the quantity of gas they receive).

Conversely, in light of increased gas flow and price volatility, market participants require greater flexibility in order to reduce their exposure to high spot market prices and take advantage of low priced gas for their own use or to arbitrage between markets. Participants that purchase their gas through the DWGM (instead of physically hedging their position with a GSA) are exposed to price volatility, while those with GSAs may find themselves having to buy or sell gas through the DWGM to manage supply and demand variability.[47] Additional means to manage market price risk are now required.

In mature markets we would expect financial hedging to be an alternative to taking physical positions. Financial hedges/positions allow counterparties to agree today to a financial transaction in the future based on the price of an underlying asset, such as the DWGM market price. As the value of the financial product is *derived* from the value of the underlying asset, these products are also called "derivatives". While a market participant may be physically out of balance and hence owe (or receive) money from the spot market, their total financial exposure is hedged through this additional financial transaction.

As with the DWGM, the National Electricity Market (NEM) is designed to be only a spot market. An active financial derivatives market has emerged as a "side market" to the NEM, which provides market participants considerable flexibility in the way they manage risk and provides an effective alternative to physical positions.

However, a liquid financial derivatives market has not emerged as a side market to the DWGM. While the Australian Securities Exchange (ASX) has released a number of such products, no material trading in them has developed.[48] Due to different physical characteristics of gas compared to electricity, the design of the DWGM spot market is

46 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, July 2015, p. 119.

47 The Commission understands that short term trades of gas outside of the DWGM are limited by high search and transaction costs and a lack of public information on the prices paid for gas, which means that participants are unable to readily assess the market value.

48 See the ASX website at http://www.asx.com.au/products/energy-derivatives/natural-gas.htm, accessed 22 September 2016.

considerably more complex than the NEM spot market. This complexity has not been conducive to the development of a financial derivatives market. In particular:

- The DWGM's multiple pricing schedules do not appear to be consistent with the development of financial risk management products. In order to fully manage commodity risk, a financial derivative contract for the DWGM would need to be settled on the basis of an individual market participant's exposure (through both imbalance payments and deviation payments) to the 6.00am and intra-day prices. Were a financial derivative to be referenced by only the 6.00am price, as the current financial derivatives offered by the ASX are, then any exposure to a change in the market price over the course of the gas day would not be hedged.

- Developing an exchange-traded futures contract to hedge the risk of intra-day rescheduling is likely to be administratively complex in the case of the DWGM. This is because the financial transfers are no longer dependent on movements in a single benchmark price (the 6.00am price), but also an individual participant's exposure to each of the pricing intervals throughout the day. As the interval prices are generally a function of how well participants forecast their demand ahead of the gas day, valuing this risk may be more complex for counterparties than a standard futures contract derived from a single benchmark price.

- Financial derivative products based on the daily and/or intra-day market prices do not hedge again residual price risk arising from uplift payments. While congestion uplift can be hedged by holding AMDQ rights, this protection only exists when a market participant is injecting gas, and hence is not available to parties solely consuming gas. Surprise and common uplift cannot be hedged.

- The requirement to inject gas to receive congestion uplift protection through AMDQ rights may create an incentive for market participants to take physical positions (i.e. inject their own gas to meet their demand) rather than financial positions in the DWGM (i.e. not inject their own gas, buy gas at the spot price through the DWGM, and hedge the spot price risk through a financial derivative).

As a consequence, market participants are unable to use financial products to manage risks associated with being short or long gas.

Volume risk associated with capacity shortfalls

Market participants face the risk of being constrained off in the event of a constraint, and not being scheduled to inject despite offering gas at a price less than the market price.

AMDQ provides holders a tie-breaking right – when there are equally priced injection bids, market participants with AMDQ are scheduled first. This is particularly useful to a market participant offering gas at $0/GJ to meet its own demand and so avoid exposure to the market price. Because many market participants undertake this risk management strategy, a large proportion of gas is bid at $0/GJ. If there is a constraint such that some gas offered at $0/GJ must be constrained off, those market participants with AMDQ will be scheduled first.[49]

However, if the holder of AMDQ offers at a price higher than a market participant without AMDQ, the AMDQ holder may be constrained off, as a result of AEMO's algorithm which schedules the lowest priced gas to meet demand. For example, a market participant holding AMDQ and bidding at $0.01/GJ would be constrained off ahead of a market participant without AMDQ offering gas at $0.00/GJ.

AMDQ therefore only offers limited protection against volume risk associated with capacity constraints, which cannot be hedged through other means.

Summary of risk management issues

To summarise, as a consequence of the DWGM's core design, market participants are unable to enter into physical positions to manage their risk through the DWGM itself.

During the more stable market environment of the recent past, market participants have entered into physical hedges through long-term GSAs. However, as GSAs become less flexible and higher priced, and market participants need to more actively manage their portfolios as a consequence of market changes introduced with the growing LNG export industry, alternative means to manage risk are likely to be required.

However, it seems unlikely that financial derivative trading can develop with the current design of the DWGM, due to intra-day pricing, uplift charges and incentives on participants to take physical positions.

Furthermore, market participants are also exposed to volume risk associated with capacity shortfalls which cannot be fully hedged.

Consequently, DWGM participants currently face wholesale trading risks which may result in consumers paying more than is necessary for gas. This is likely to become an increasingly important issue in the future. In this context, the existing gas market arrangements in the DWGM do not appear able to support the outcomes envisaged by the Energy Council's Vision, particularly in light of the structural changes underway in the gas sector.

2.4.2 Transparent and meaningful gas prices

Market outcomes are a function of the quality of information available to market participants. An effective gas market is one that can deliver to participants meaningful, market-based reference prices for gas that reflects underlying supply and demand

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49 The tie-breaking right applies regardless of whether there is a constraint or not. Without a constraint, two or more market participants may coincidently offer gas at a price *equal to* the market price, in which case market participants with AMDQ would be scheduled ahead of the market participants without.

conditions. Such prices can provide signals to drive the efficient use of gas in the short-term, while promoting efficient levels of investment in physical supply in the long-term.

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

An efficient market-based reference price for gas that is credible in the eyes of participants requires sufficient trading liquidity, to provide confidence that the market price represents the underlying value of gas.

Current market arrangements are unable to deliver a meaningful, market-based reference price for natural gas which reflects underlying supply and demand condition in both the short and long term, and so are unlikely to support the achievement of this aspect of the Vision. While the DWGM spot price reflects immediate supply and demand conditions, it is not representative of the longer term. Long term trades (such as GSAs) are negotiated bilaterally, with the terms and price kept confidential. As discussed above, a liquid financial derivatives market has not emerged, which, in addition to reducing risk management options, also reduces the amount of information available to market participants to make informed decisions.

2.4.3 Limited market-driven investment in the DTS

A regulatory approach to investment in the DTS

Investment decisions in the DTS generally result from a regulatory process, as part of the AER's review of APA's access arrangement for the DTS. Consequently, the existing approach does not support the Vision's objective of a supportive regulatory framework for investment that occurs in response to market signals.

Access arrangement reviews tend to occur on a five yearly basis, and involve APA submitting proposed capital expenditure projects to the AER, with supporting information to justify the expense. The AER takes these proposals and any other information it is able to gather into account to assess (*ex ante*) whether the forecast capital expenditure associated with each project is likely to be 'prudent' and meet the test for conforming capital expenditure set out in the national gas rules (NGR).[50] The AER then determines APA's reference tariffs for the forthcoming access arrangement period to reflect the value of new capital expenditure forecast to occur within the access arrangement period that is reasonably expected to satisfy the requirements in

50 Rule 79 of the NGR sets out the matters the AER must consider when determining whether or not capital expenditure can be rolled into the capital base.

the NGR. However, APA is not obliged to develop the projects it proposed to the AER during the review which formed the basis of the AER's determination.

At the next access arrangement review, the AER considers (*ex post*) whether capital expenditure actually incurred by APA in the previous period was prudent.[51] Any capital expenditure actually incurred but deemed not to be prudent is then removed from the asset base, and so associated costs are not recovered through reference tariffs for the next access arrangement period. This *ex post* review may provide incentives for APA to only undertake investment that had been assessed (*ex ante*) by the regulator to be prudent, and not to undertake investment that it may consider to be prudent but which has not yet been assessed as such by the AER through the regulatory process.

The costs of all investments approved through the regulatory process are currently recovered through volumetric tariffs levied on market participants, with participants passing these costs through to end users.

Why a regulatory approach is required in the DTS

The regulatory approach to investment decision-making contrasts to the market-led approach for all other gas transmission pipelines in Australia, where investment made by pipeline owners is underwritten by market participants through long-term contracts.

In the DTS, the regulatory process to investment decision making is a consequence of a "free-rider" problem associated with the market-led approach. As access to the DTS is allocated on the basis of DWGM market outcomes, market participants cannot obtain exclusive firm access rights. Consequently, a market participant:

- will not be provided access to the DTS if it offers above or bids below the market price (unless it happens to be constrained on); and
- may not be provided access to the DTS even if it offers below the market price, in the event of a constraint.

While market participants are able to contribute wholly or in part to investment in the DTS, without exclusive rights to use the DTS, individual market participants have little incentive to do this. Other market participants would also benefit from a capacity expansion, without having contributed to its costs, and may even prevent the funding participant from using it. Market-led investment is therefore unlikely to eventuate under the current arrangements.[52]

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51 Rule 79 is also used for this assessment.

52 Significant investment has been undertaken outside of this regulatory process, for example to support additional flows to Culcairn in recent years. However, in this case, to some extent this investment was able to proceed due to the contractual commitments entered into by shippers on the Moomba to Sydney Pipeline (MSP) side of the Interconnect. If the DTS and MSP had been owned by different parties, this investment may not have proceeded.

The benefits of a market-led approach to investment

The regulatory process for investment decision making has two substantial drawbacks compared to a market-led approach (absent of the free-rider problem which arises from allocating capacity through the DWGM).

Firstly, the regulator is unlikely to have the same information or incentives to make efficient decisions compared to a market participant. The five yearly cycle of determinations has also led to concerns that investment decisions have been insufficiently timely in the past or will react quickly enough to emerging issues. The market-led approach (absent of the free-rider problem arising from the allocation of capacity through the DWGM) is therefore likely to result in more efficient and more timely investment decisions.

Secondly, if despite the likely improved decision making under a market-led approach an inefficient investment decision is made, the market participant, rather than consumers, would bear the cost of this decision. Furthermore, as part of an interconnected network, investment in the DTS is increasingly made for the benefit of consumers outside of the DTS, despite the cost and risk being borne by Victorian consumers.

Indeed, it is for these reasons that a market-led approach is preferred outside of the DWGM, where the free-rider problem resulting from the DWGM's design does not exist.

The Commission recognises there are a number of provisions in the NGR which aim to address the inefficiencies that arise in a regulatory approach to investment decision making. For example:

- Redundant asset provisions allow for assets that cease to contribute in any way to the delivery of pipeline services to be removed from the regulated asset base, and hence the associated costs not recovered from consumers through regulated tariffs.[53] This provides a mechanism by which the risk of inefficient investment is not borne by consumers.

- Investment decisions can be made on a more timely basis than the five year regulatory cycle through AER's power to make advance determination with regard to future capital expenditure.[54]

Nevertheless, the Commission considers that even with these measures, the regulatory approach to investment decision making is a second best alternative to a well-functioning market-led approach.

Box 2.5 below provides an example of how regulatory decision making in the DTS may result in inefficient outcomes.

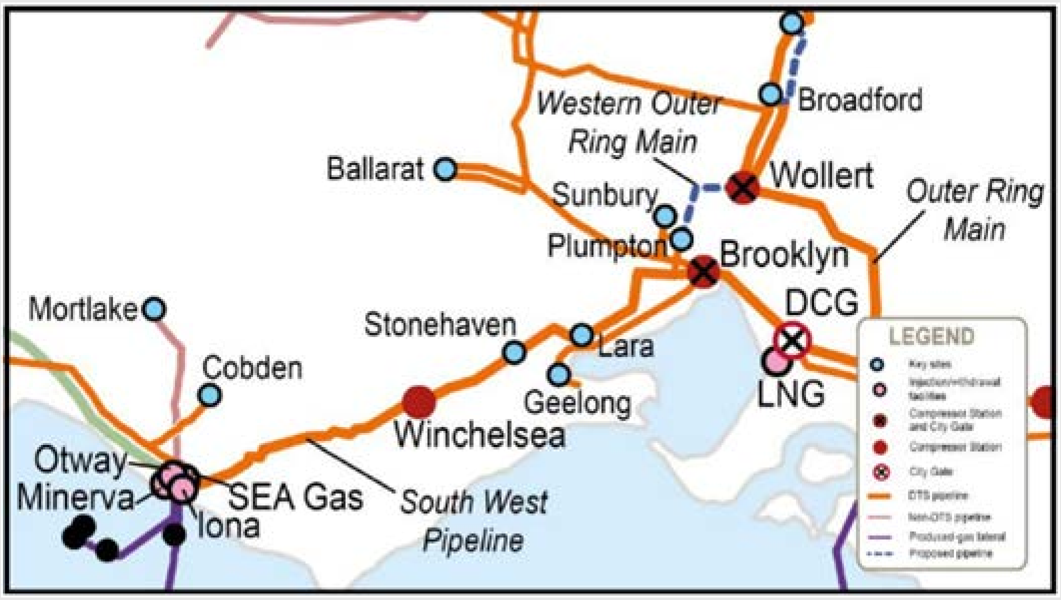
53 Rule 85 of the NGR.

54 Rule 80 of the NGR.

Box 2.5 Investment in the DTS to support Iona storage

The Iona underground storage facility operates in refill mode during summer (when the net flow of gas is from the DTS) or in injection mode during winter (when the net flow of gas is into the DTS). The facility can also be accept gas from the Port Campbell production zone (outside of the DTS), and deliver gas to the SEAGas and Mortlake pipelines (also outside of the DTS)

Figure 2.4 Map of Iona and surrounding area



Source: AEMO, *Update Victorian gas planning report*, February 2016

During the summer of 2015-2016, a number of events at the Brooklyn compressor station near Melbourne restricted the ability of the Iona facility to refill. At the same time, production in the Port Campbell area declined, so less gas could be delivered to the Iona storage facility from that source. The outcome was that during the remaining months of summer, market participants were seeking to refill at maximum possible rates to ensure there was adequate gas available for use in the winter of 2016.

To achieve this, market participants were bidding to withdraw at the maximum allowable price with total quantities exceeding the available transport capacity to Iona. As a result, some market participants were constrained off, resulting in negative financial consequences through the DWGM and inhibiting their preparation for winter.

Taking a longer-term perspective, if production at the Port Campbell zone continues to decline and limited gas is directed from Moomba to South Australia demand, the additional flow to support gas demand in South Australia is likely to come from the Iona underground storage facility. This means that there is likely to be increased demand for transmission capacity to flow gas to the Iona underground storage facility, and over a longer period than the current October/November to April/May.

While AEMO's 2016 Victorian Gas Planning Report Update has identified that additional DTS capacity to refill Iona could be provided through a number of different augmentations, APA must either augment the pipeline underwritten by private arrangements with market participants (which is unlikely due to the free-rider problem described above) or obtain permission from the AER under its access arrangement for an augmentation to be added to their capital base and recover the costs based on transmission tariffs.

For the reasons described above, there is considerable uncertainty as to whether this represents an enduring issue and the AER is not as well placed as market participants to make an efficient investment decision, which requires complex forecasts of likely outcomes across the east coast gas market.

If the augmentation is approved and commissioned, the transmission tariffs will mean all costs are recovered from consumers over an extended period. If approved and the investment is inefficient the consumers will bear the costs. If it was not approved was efficient, then consumers will ultimately bear the costs of constraints which would otherwise have been avoided.

2.4.4 Trading between hub locations

Due to the confidential nature of gas supply agreements across eastern Australia, and gas transportation agreements outside of the DTS,[55] it is difficult to assess the materiality of current trade between the DWGM and other east coast gas markets.

Nevertheless, outside of the DTS, the ability of users to access capacity contracted to others through trades emerged as a major theme for the East Coast Gas review.[56] Consequently, the AEMC made a number of recommendations to improve access to pipeline capacity outside of the DTS, in part to improve opportunities for trading between locations.

Furthermore, it is likely that the disjointed nature of market arrangements across eastern Australia is inhibiting trading between locations. There are currently three different facilitative market designs (the DWGM, STTM and GSH) with six pricing points. The complexity for market participants to operating under multiple markets designs is likely to increase transaction costs, and hence reduce trading between locations.

For those market participants seeking to ship gas across the DTS and onwards (for example from Longford to Adelaide), the requirement to bid and offer gas into the DWGM (despite not actually wishing to trade gas) presents an additional layer of complexity they need to manage. It also requires market participants to incur fees related to the operation of the DWGM. These issues may be inhibiting trade between locations.

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55 Capacity outside of the DTS is allocated under a "contract carriage" approach whereby shippers contract capacity with pipeline owners.

56 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review,* Stage 2 Final Report, May 2016, chapter 5.

3 Overview of Southern Hub model and rationale for change

Box 3.1 Recommendations

The Southern Hub model unbundles the three roles currently undertaken through the DWGM: gas commodity trading; pipeline capacity allocation; and balancing responsibility.

Recommendation 1: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.

Recommendation 2: Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.

Recommendation 3: The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.

Given the risk that, on commencement of the Southern Hub, participants do not actively trade gas and liquidity does not develop, the Commission has examined a number of transitional measures to stimulate liquidity or minimise the financial impacts of low liquidity.

Recommendation 4: Market trials should be undertaken to determine the requirement for, and design of, transitional measures that may be appropriate to help stimulate liquidity in the commodity market and mitigate the impacts of changed market arrangements for market participants.

The Gas Market Reform Group (GMRG) was established by the COAG Energy Council to progress the suite of reforms related to the East Coast Review. The Commission considers this group to be the most appropriate to further develop and implement the DWGM reforms.

Recommendation 5: The COAG Energy Council should task the Gas Market Reform Group (GMRG) to implement the Commission's recommended reforms to the DWGM (Recommendations 1-4) and the corresponding required design features. The GMRG should also take into account any preferred and suggested elements outlined by the Commission.

To give effect to the DWGM reforms, the GMRG would develop and propose the details of recommended NGL changes to the COAG Energy Council and the details of recommended NGR changes to the AEMC.

3.1 An overview of the proposed design for the Southern hub

To address the challenges emerging in the market, achieve the Energy Council's Vision and promote the NGO, the Commission recommends replacing the existing DWGM with a new Southern Hub gas trading model. Although this would represent a significant change, the Commission considers this to be necessary because the issues arising in the current market are the result of intrinsic design features in the DWGM.

The Southern Hub unbundles the three roles currently undertaken through the DWGM. The key features of the Southern Hub design are outlined below, with a more detailed description provided in Chapters 4 to 6 and an accompanying technical report.

3.1.1 Gas trading on the Southern Hub

Recommendation 1: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.

The trading of gas through the Southern Hub would be significantly different to the current DWGM. Instead of market participants being required to bid and offer all of their gas in order to both gain access to the DTS and trade gas on the DWGM, market participants:

- would be required to nominate their required flows of gas into and out of the DTS; and
- may voluntarily trade some or all of their gas inside the DTS, including through an exchange based on the Gas Supply Hub design.[57] Market participants would be able to place bids or offers for any gas they wish to trade which would then be automatically matched through the exchange.

Importantly, forward products could be traded through the exchange (say, for gas on a day next week, or for all of next month), enabling market participants to better manage their price risk.

The Southern Hub would be a virtual hub – any bids and offers could be matched regardless of the actual injection and withdrawal points for the gas. The footprint of the virtual hub would be the same as currently, i.e. the DTS.

Trading would be continuous: bids and offers could be placed, and trades executed, at any time, rather than occurring through the current regular scheduling process.

57 While participation in the market to buy or sell gas would be voluntary, market participants would be subject to the mandatory balancing mechanism, discussed in section 3.1.2 below.

3.1.2 Managing system balancing

Recommendation 2: Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.

System balancing would be managed through a mandatory balancing mechanism.

Instead of AEMO managing balancing through the scheduling process and actively buying or selling gas for any deviations between market participants' scheduled and actual withdrawals (as is currently the case), each market participant would have primary responsibility for their own balance between injections and withdrawals. This responsibility would be conferred though financial incentives, where an individual market participant would incur costs if it was out of balance at the time that AEMO, as system operator, needed to undertake residual balancing action because the system as a whole was not sufficiently in balance.

Acted upon collectively, market participants' individual incentives to be in balance (at the specific times system security was threatened) would promote keeping the system as a whole sufficiently in balance such that the need for AEMO to take balancing actions would be reduced.

Market participants would be able to adjust their injections or withdrawals, or trade gas (including through the exchange), so that they would be individually closer to being in balance. Box 3.2 provides an example of how market participants would be able to stay in balance.

If, however, the system as a whole became sufficiently out of balance so as to threaten system security, AEMO would undertake a residual balancing action: buying or selling gas on the exchange so as to increase or decrease the amount of system linepack. The cost of residual balancing actions would be attributed to those market participants which caused the need to undertake the action.

As a continuous balancing regime, market participants would only be incentivised to be in balance when the system as a whole was approaching its secure limits. Linepack would be efficiently used the rest of the time, and market participants would not be required to be required to be in balance at any particular pre-determined time (such as at the end of the gas day). Importantly, however, AEMO's residual balancing role would apply on a continuous basis, rather than the current periodic scheduling basis. This would serve to enhance system security relative to the current arrangements.

In some instances, localised constraints may arise even if the system as a whole is sufficiently in balance. For example, demand or injections may be unexpectedly high at specific locations. To address these localised issues, AEMO may also need to take alternative actions such as buying or selling gas at a specific location, or buying back entry rights so as to reduce injections. Furthermore, in emergencies, AEMO would also be able to direct market participants to inject or withdraw gas.

AEMO's residual balancing actions would guarantee delivery of gas (providing the DTS was physically capable) even if a market participant or its counterparty was short of gas.

3.1.3 Managing the flow of gas consistent with its physical capacity

Recommendation 3: The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.

Entry and exit rights obtained and held by market participants would be used to manage the flow of gas on the system consistent with its physical capacity, under a system known as "entry-exit".

The number of entry and exit rights made available would be consistent with the physical capacity of the system, meaning that in normal circumstances, flows would not exceed the physical capacity of the system.

Rights to existing capacity would be allocated through a variety of market and non-market mechanisms in the short and long term, on a non-discriminatory basis. Notably, exit capacity to distribution networks (primarily to serve residential demand) would be directly allocated on the basis of daily usage, and not allocated through a market.[58]

Additional capacity rights to exit capacity (other than to distribution networks) and entry capacity would be made available if market participants were willing to underwrite investment to expand the physical capacity of the system. Capacity expansions would not be made unless there was commitment from market participants. Market participants' collective commitment to underwrite a proportion of capacity would be used as a signal by the AER to approve capacity expansions.

Capacity expansions to meet demand at distribution connected exit points would be approved by the AER as part of the Access Arrangement review process, and not through a market-led process.

Secondary capacity trading would be supported and encouraged, and mechanisms which ensure the release of capacity in the short term would be introduced, to provide market participants access to the DTS if they valued it sufficiently.

AEMO would be responsible for managing the physical flow of gas on the DTS between injection points and withdrawal points consistent with market participants' nominations. Market participants would be responsible for the transport of gas outside of the DTS (i.e. to injection points and from withdrawal points).

58 Dynamically allocating exit capacity to distribution networks avoids potential issues in efficiently allocating capacity between market participants as a result of end consumer churn and removes any potential barriers to entry for new retailers.

Box 3.2 An example, combining all three elements of the Southern Hub

As a virtual hub, market participants would not themselves be responsible for flowing gas across the system. To avoid being exposed to the costs of residual balancing actions, a market participant would need to remain in balance such that its cumulative injections (and purchases) equal its cumulative withdrawals (and sales).[59] It could:

- hold sufficient entry rights and nominate to inject gas at point A and hold sufficient exit rights to withdraw the same amount of gas at point B, without trading gas. AEMO would be responsible for delivery of gas (but not necessary the same molecules of gas); or
- not inject any gas, purchase gas injected by another market participant on the exchange, and then withdraw the gas consistent with its exit rights; or
- inject gas consistent with its entry rights and then sell the gas on the exchange to another market participant who would then withdraw the gas; or
- a combination of the above.

3.2 Benefits of the proposed Southern Hub

Separating the three processes currently undertaken through the DWGM has a number of substantial benefits compared to the existing DWGM.

These benefits arise as a consequence of addressing long-standing concerns regarding the DWGM's design which are being exacerbated by the changing market dynamics on the east coast. Consequently, the ability of the existing DWGM market design to meet the emerging challenges will be limited regardless of whether other reforms recommended by the Commission in the East Coast Gas Review proceed.

Conversely, while there would be synergies in implementing the Southern Hub in conjunction with the other east coast gas market reforms, the intrinsic nature of the long-standing concerns with the DWGM design mean that they should be addressed through implementation of the Southern Hub even in the absence of broader reform across the east coast.

The benefits of the Southern Hub model are discussed below.

59 A market participant would also not be exposed to the costs of residual balancing actions if it was out of balance in the opposite direction to the system as a whole.

3.2.1 Improved ability to manage risk

As discussed in section 2.3.1, allocating capacity through the DWGM requires that bids and offers be placed by market participants for all gas for the upcoming day. These bids and offers are used as an input to AEMO's scheduling algorithm which allocates capacity for the upcoming day.

By separating the capacity allocation process and managing capacity through an alternative process (nominations consistent with capacity rights, themselves consistent with the physical capacity of the system), there would no longer be a requirement for all gas to be bid or offered on a regular basis for daily/intraday products. Market participants would instead be able to trade products of a variety of lengths on a voluntary basis.

The key benefit of this is that market participants would be able to trade gas for physical delivery in the future *through the Southern Hub itself.* Allowing participants to agree the delivery of gas in the future at a price agreed today would provide them with an additional means to manage their risk - either through long term products akin to current bilaterally negotiated GSAs, or shorter term products. Market participants would be able to do this continuously, providing further flexibility. The exchange would not foreclose existing means to trade gas in advance, for example outside of the Southern Hub through traditional GSAs, and would continue to allow for the trading on gas on the day (i.e. it would have a spot product).

For the exchange to improve risk management options, the exchange should be sufficiently liquid, so that market participants can be confident that the price struck is representative of underlying supply and demand conditions. A number of characteristics in both the design of the Southern Hub and the existing Victorian gas sector are likely to promote liquidity in the new exchange and thus improve the ability of the Southern Hub to manage risk:

- The Southern Hub is a virtual hub meaning that gas anywhere in the hub is fungible, irrespective of location. This serves to concentrate liquidity.
- Market participants would be incentivised to "trade out" imbalances at the Southern Hub through the mandatory balancing regime, which promotes trading activity.
- The variable, and unexpected, nature of demand in Victoria creates a short-term need to trade gas as a result of gas supply and demand differing from what was expected. The management by AEMO of such events through the exchange (in its residual balancing role) will prompt participants to place offers and bids on the exchange, which will be available to all participants to enable them to manage their own positions.
- The existing DWGM has the largest concentration of buyers and sellers of all current facilitated markets on the east coast.

Price discovery would occur via the exchange initially in that a daily summary of prices struck for exchange traded products would be published (as is done at the Wallumbilla GSH), including a volume-weighted end of day price at the Southern Hub.

Over time, various price reporting agencies may choose to report reference prices as they do in other gas markets, which are typically based off an amalgam of both exchange trades and bilateral trades. However, the Commission notes that these bodies provide a service in the commercial interests of gas market participants and considers that their role in the Southern Hub will emerge over time if demanded by the market.

The establishment of exchange-based trading would allow for innovation in products offered and for standardised products to emerge (e.g. day-ahead products, monthly products and winter 2020 products) and market forces will determine the success of individual products – that is, products will be traded only to the extent that they are useful to participants. This standardisation encourages transactional efficiency and the development of liquidity.

Reported prices on standardised and liquid physical products should better reflect underlying supply and demand conditions over a variety of timeframes, which might provide better pre-conditions for liquid financial derivative products to emerge than in the current market. Financially traded products typically require a standardised underlying physical product that is commonly traded to reference. These financial derivatives may provide a further additional means for market participants to manage their risk.

3.2.2 More transparent and meaningful gas prices

The prices on a liquid Southern Hub exchange and any liquid financial derivatives market that might also emerge would provide market participants with transparent and meaningful reference prices that reflect both short and long term supply and demand conditions. This contrasts to the existing DWGM, where the only transparent prices are the DWGM spot prices – reflective only of immediate supply and demand conditions.

Bids and offers for a variety of gas products at the Southern Hub of different delivery dates and tenors would be transparently displayed on the exchange, preferably alongside bids and offers for commodity products at the Northern Hub and capacity products being exchanged between market participants. A time series of prices for products could then be collated and published by the exchange operator or price reporting agencies. An example of a simplified, stylised trading platform screen is provided in figure Figure 3.1.

Figure 3.1 Stylised trading platform

	COMMODITY								CAPACITY					
	Northern Hub				Southern Hub				Longford entry				Culcairn exit	Culcairn_ Syd
Tenure	Qty	Bid	Off	Qty	Qty	Bid	Off	Qty	Qty	Bid	Off	Qty	[EXAMPLES OF OTHER POSSIBLE CAPACITY PRODUCTS]	
Balance of day	5	4.00	4.75	10	10	7.20	7.80	2						
	5	4.50	4.90	5										
Day-ahead	1	5.50	6.20	2					1	1.50	1.20	1		
			5.00	1										
Week-ahead					5	6.00	6.80	15						
					5	6.50								
Month-ahead	2	5.00			1	6.00	6.80	15	5	1.00	1.50	5		
									1	1.50				
Winter16														
Q416					10	5.00	5.50	5						

Better longer term reference prices (i.e. greater than day ahead/on the day) can provide signals to promote efficient use of gas and efficient levels of investment, throughout the supply chain.

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

3.2.3 Increased market driven investment in the DTS

Under the Southern Hub model, market participants would have significantly improved incentives to underwrite capacity expansions for entry and non-distribution connected exit points on the DTS because, in return, they would be able to secure firm access rights to the capacity created.

This contrasts with the existing arrangements, where a free-rider problem exists as a result of the DWGM's design meaning that typically, investment occurs through a regulatory process. Market participants have little incentive to underwrite capacity because it is allocated through the DWGM and not exclusively to the funding market participant.

Under the Southern Hub model, investment decision-making would not be purely market-led, and would retain some elements of regulatory decision making:

- Investment decisions for capacity for distribution connected exit points would retain broadly the existing regulatory approach, because firm rights to these exit points would be allocated on a dynamic basis.

- A degree of regulatory decision making would also be required for other investments (for example, market participants may only collectively need to commit to underwrite a proportion of the costs of an expansion for it to be undertaken, requiring regulatory decision making to determine whether the investment as a whole is prudent).

Importantly, however, market participants' improved incentives to commit to underwrite investment (other than for non-distribution connected exit points) would provide signals to the regulator in making its decision. This approach has a number of advantages over the current approach:

- market participants are likely to have incentives and information to provide signals to the regulator as to whether an investment is efficient;
- if an investment decision is not efficient despite market participants' signals, a greater proportion of the cost of the investment is borne by market participants and not by consumers; and
- investment decisions can be made in a more timely manner than through the existing five-year Access Arrangement cycle.

Furthermore, no capacity expansions to increase entry or exit capacity (other than to distribution networks) would occur other than based on a signal provided by market participants to commit to underwrite at least a proportion of the costs of a capacity expansion.

Market participants would be able to signal investment needs not just immediately at the entry or exit point, but deep into the network, because this deeper network capacity would be necessary to support the flows of gas across the system consistent with the amount of capacity rights released. The benefits a more market-led approach to investment would therefore not be confined to investment at the immediate edge of the DTS.

Furthermore, a more market-led investment processes should improve not only the efficiency of capacity investment for gas for delivery within the DTS, but also in capacity to deliver gas across the system and into interconnected pipelines, for consumption outside of the DTS.

3.2.4 Improved trading between hub locations

An additional benefit to the proposed reforms would be that the trading exchange would be similar to that in operation at the Northern Hub. Not only would this provide a low cost, anonymous and transparent way for participants to trade, it would support implementation of common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. This should lower transaction costs and complexity for traders operating across multiple markets, encouraging greater participation in the east coast market.

For those market participants wishing to transport gas across the DTS for delivery into other areas of eastern Australia, the Southern Hub should be a considerably easier market in which to transact. Instead of having to bid and offer gas into DWGM on a daily basis (and buying their own gas from themselves), market participants would ensure that they had sufficient entry and exit rights, and simply nominate injections and withdrawals. They would not be required to interact with the Southern Hub gas exchange at all.[60]

Furthermore, the proposed design would mean that costs associated with the exchange would not be attributed to those market participants wishing to use the DTS but not trading on it.

3.2.5 Reduced barriers to entry

Under the Southern Hub arrangements, market participants would have greater flexibility in buying and selling gas, and managing risk. Relative to the existing arrangements, this should allow a greater variety of market participants to enter the market and subsequently expand.

The Southern Hub would provide alternatives to the bilateral contracting options currently available to participants. Bilateral contracting may be difficult for new producers or gas users to use to enter the market, as they may not have the resources to negotiate on an equal basis with incumbents. Instead, if new entrants – whether they may be small producers, gas users or participants in other east coast markets – have accurate price information, they would be able to readily buy or sell gas on a market on an equal basis to other players. Liquid markets can therefore encourage participation and promote competition.

3.2.6 Improved management of system security

Currently, system security is maintained primarily through the DWGM's regular scheduling processes, with AEMO buying or selling gas to meet an end-of-day linepack target.

Under the Southern Hub model, system security would be maintained through a mandatory and continuous balancing mechanism. The model would provide financial incentives on market participants to remain in balance. However, as system operator, AEMO would be ultimately responsible for ensuring system security and would have a residual balancing role. Under that role, AEMO would be obliged to take action where market participants are not collectively sufficiently in balance to maintain system security. AEMO’s residual balancing role would apply on a continuous basis to enhance confidence in system security relative to the current arrangements in which balancing is normally undertaken on a discrete-time periodic basis.

60 In most cases it would be expected that injections and withdrawals associated with flows to other pipelines would be relatively flat, and hence there would also be minimal interaction with the balancing regime.

Market participants would individually be provided financial incentives to be in balance (at those times when the system was approaching secure limits) which, acted upon collectively, would be consistent with maintaining the balance of the overall system. Market participants would be able to act continuously to adjust their individual balance position (and hence the linepack of the system as a whole), rather than system security actions being limited (in normal circumstances) to the scheduling timetable, as is currently the case.

If the system nevertheless approached its secure limits despite these financial incentives, AEMO would be able to buy or sell gas, or take other system security actions. It would take these actions at any time, rather than through the current scheduling process. These actions would ensure the delivery of gas.

A number of stakeholders have raised concerns that the system operator's ability to act as residual balancer would be limited if liquidity in the on-the-day commodity market at the Southern Hub is low.[61] While this could mean that AEMO's balancing actions could be expensive, as a counterparty to AEMO's balancing action trade could price the trade highly, *system security* would not be threatened – at some price, counterparties will trade with AEMO to alleviate any system security issue. Additionally, AEMO would retain its existing powers to direct market participants in extreme circumstances to address the most serious or imminent system security issues.

More generally, the Commission is considering ways to address the risk of low liquidity in the capacity market, as outlined in section 3.3.2 and chapter 7.

3.2.7 Assessing the benefits of reform

The AEMC engaged PricewaterhouseCoopers Australia (PwC) to undertake a high level estimate of the potential economic benefits and costs of implementing the Southern Hub model.[62]

The methodology applied by PwC to estimate the benefits and costs of introducing the Southern Hub model is consistent with its May 2016 analysis of the benefits and costs of the AEMC’s overall east coast gas market reforms, as recommended in the AEMC's East Coast Gas Review.[63]

PwC's analysis estimates that by 2040, the impact on GDP of the AEMC's draft recommendation to implement the Southern Hub model would be between 0.01 per cent and 0.05 per cent higher than the base case (which assumed the other reforms recommended in the East Coast Gas Review were implemented). This equates to an annual increase in GDP of between $0.2 billion to $1.7 billion by 2040, even once implementation costs have been considered. The most important contributor to this was the productivity effect, which is explained further in Box 3.3.

61 For example, see: AEMO, Submission to the March discussion paper, pp. 15-16.

62 PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, October 2016.

63 PwC, *Cost benefit analysis of gas market reforms*, May 2016.

Table 3.1 PwC's estimated impacts of the reforms on GDP ($bn and % deviation from baseline)

	2030		2040		Present value
	%	$bn	%	$bn	$bn
Low scenario	0.01%	0.2	0.01%	0.2	1.7
Central scenario	0.02%	0.6	0.03%	0.9	4.6
High scenario	0.05%	1.2	0.05%	1.7	12.2

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

PwC estimates that these net benefits can be realised through one-off implementation costs of between $44 million and $211 million and ongoing annual costs of between $3 million and $42 million. This equates to a net present value cost of between $58 million and $480 million (to 2040).

Table 3.2 PwC's estimated total costs ($m 2015-16)

	One-off implementation costs	Ongoing annual costs	Total costs over 10 years (discounted)	Total costs to 2040 (discounted)
	$m	$m	$m	$m
Low scenario	44	3	43	58
Central scenario	100	14	121	184
High scenario	211	42	184	480

Note: Totals are subject to rounding. Discounted costs are calculated using a real discount rate of 7 per cent. Source: PwC analysis.

On the basis of the central scenarios, the introduction of the Southern Hub model represents about 69 per cent of the costs for the entire package of reforms recommended in the AEMC's East Coast Gas Review and about 53 per cent of the benefits.

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

The PwC report setting out its cost benefit analysis of the AEMC's Southern Hub accompanies this Draft Final Report and can be found on the AEMC's website, while the approach taken by PwC to its cost-benefit analysis is summarised in Box 3.3.

Box 3.3 Approach to the cost-benefit analysis

The cost-benefit analysis conducted by PwC reflects a reform where the benefits are likely to be widespread across the economy and the costs are borne by market participants and the market operator. Accordingly, PwC's approach estimates the net economic benefits once the reform is implemented, and for reference, provides an estimate of the investment required by stakeholders to implement the reform.[64]

The approach to the cost-benefit analysis was to estimate the size of the potential impacts of the reform on the Australian economy on the assumption that the qualitatively identified benefits of the reform emerge, consistent with progression towards achieving the Energy Council's Vision.

The costs associated with the Southern Hub development were estimated by PwC in its analysis of the wider east coast reforms. These costs were used by PwC as a starting point for further stakeholder consultations. A survey of key DWGM stakeholders was conducted in August 2016 to test the original (April 2016) cost estimates provided through industry consultations and to gather stakeholder feedback on qualitative benefits. Costs assessed as part of PwC analysis include planning costs, upfront implementation costs and ongoing annual costs based on increased effort required to interact with new processes and systems.

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

Reflecting these flow-on effects, PwC's approach used in the analysis was to quantify both the direct and indirect economic impacts through an economy-wide, general equilibrium analysis. This involves quantifying the impact of the reforms on macroeconomic variables such as gross domestic product (GDP), employment and household consumption through a computable general equilibrium (CGE) model. CGE modelling is the standard approach used to understand the macroeconomic (direct and indirect) impacts of a change in economic policy settings.[65] It is commonly used by policy agencies when

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

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

undertaking tasks such as these, for example by the Industry Commission when assessing the Hilmer reforms.[66]

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

For the purpose of this analysis, the base case assumes that the other reforms recommended in the AEMC's East Coast Gas Review would be implemented. The base case includes assumptions about structural changes in the gas market, including the likely path of projected gas production, LNG exports and domestic use of gas reflected in AEMO's forecasts.

The policy case simulates the economy with 'shocks' to the base case to represent the direct impacts of the reform on gas market participants. In PwC's analysis of the reforms recommended in the East Coast Gas Review, shocks were developed from theoretical analysis and conservative estimates from empirical literature on similar reforms, which were then refined with contextual information on the East Coast gas market and consideration of the likely timing of such impacts. As part of PwC's latest analysis, a proportion of the shocks derived in the original analysis were attributable to the DWGM reforms.

PwC modelled three phases of benefits:

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

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

3.2.8 Summary of the benefits of reform

The Southern Hub trading model would provide market participants with greater flexibility to manage risk, and greater transparency around the demand and supply conditions underlying the gas price. This would fundamentally improve the outcomes for market participants, to the ultimate benefits of consumers.

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

The Southern Hub model would introduce a mechanism which allows the market to signal the need for investment in the DTS. This will support the delivery of infrastructure which is efficiently sized, in the right location and on time.

The Southern Hub model would also improve elements of the DWGM market that have been successful to date, both in terms of stimulating a competitive retail gas market and safeguarding the security of gas supply for Victorian customers. Furthermore, transaction costs should be reduced, and reflected in end-prices to consumers.

These outcomes are consistent with the direction that gas market development should take in order to meet the Energy Council's Vision.

3.3 Addressing concerns in the Southern Hub model

A number of stakeholders have suggested potential issues with the Southern Hub model. These are summarised below, together with the Commission's considerations.

3.3.1 Liquidity in the Southern Hub commodity markets

An advantage of the Southern Hub is that it would provide market participants with greater flexibility in the way they manage their gas requirements. Participants would be able to minimise their exposure to imbalance charges by any combination of voluntarily trading gas (which could be done on a continuous basis) and adjusting their physical injections or withdrawals.

For participants to have a genuine choice as to how they manage their positions, it is important that gas trading is an attractive option. However, there is a risk that upon introducing the Southern Hub, many market participants – lacking experience with and confidence in hub trading – may initially choose to manage their imbalances entirely by adjusting their injections and withdrawals. This may precipitate a spiral of low liquidity within the hub, as participants collectively lose confidence in the market and seek to retain their flexible gas for their own potential use, instead of risking having to acquire flexible gas on the market. This outcome would diminish many of the key benefits of the reform which dependent on the development of a meaningful and liquid reference price for gas, and might also mean that gas is not allocated to its highest-valued use.[67]

There may also be some one-off adjustments that market participants would need to make as the Southern Hub is introduced. The existing market provides incentives for participants to inject more gas than they expect to withdraw, to effectively 'self-insure' against the risk and cost of being short. The overall excess of injections has enabled a number of small market participants to source relatively inexpensive gas on the DWGM under certain conditions. The new arrangements may, by removing the

67 Stakeholders raised this concern as part of the AEMC's DWGM Working Group meetings held between June and August 2016. A summary of the concerns raised on this topic, particularly in Working Group meetings 1 and 2, can be found on the AEMC's website at: aemc.gov.au.

incentives for market participants to be long of gas, limit small market participants' ability to source cheap gas in the manner to which they have become accustomed, and hence affect the role they play in providing competitive tension to the market.

In the Commission's view, neither of these concerns represents enduring problems with its recommended reforms. However, a range of transitional measures may be appropriate to stimulate liquidity at the hub and to limit the impact of the changed market design on particularly smaller participants. Over time, once liquidity has been established and market participants have adjusted, the transitional measures would be removed and the full "target model" would be implemented.

Market participants' behaviour is likely to be a key determining factor for whether transitional measures are required. Further, the likely efficacy of the various transitional measures may also be dependent on market participants' behaviour.

Recommendation 4: Market trials should be undertaken to determine the requirement for, and design of, transitional measures that may be appropriate to help stimulate liquidity in the commodity market and mitigate the impacts of changed market arrangements for market participants.

As explained in section 3.4.2, market trials are an effective way of examining likely market participant behaviour under various market designs. This would inform whether issues relating to low liquidity are likely to emerge in the Southern Hub, and the appropriateness of various transitional measures to address this potential issue.

The specific transitional measures that could be employed and the Commission's considerations are provided in Chapter 7.

3.3.2 Liquidity in the Southern Hub capacity market

Some stakeholders have also raised concerns about potential low levels of liquidity in the *capacity* market:[68]

- If entry/exit capacity cannot be easily allocated and reallocated to the parties that value it the most, then the physical flow of gas may be inefficient. This contrasts with the current DWGM, where AEMO's market clearing algorithm schedules bid/offered gas to minimise the cost of supplying the forecast gas demand subject to the pipeline system security limits.[69]
- The coordination of trades in exit capacity, entry capacity, capacity outside the DTS and commodity may be difficult if the entry and exit capacity market is illiquid. Market participants may be stranded with commodity without capacity or vice versa, and subject to discriminatory prices through the market for the outstanding component.

68 Stakeholders raised this concern as part of the AEMC's DWGM Working Group meetings held between June and August 2016. A summary of the concerns raised on this topic, particularly in Working Group meetings 1, 2 and 3, can be found on the AEMC's website at: aemc.gov.au.

- Capacity may be subject to hoarding, whereby an incumbent market participant does not sell capacity despite not needing it itself, in order to gain a competitive advantage in an up- or downstream market.

A number of stakeholders have also suggested that requiring market participants to procure entry and/or exit rights, by creating an additional hurdle for participation in the market, would represent a barrier to entry or could even cause some market participants to exit the market.[70]

As explained in greater detail in Chapter 6, the Commission is recommending a number of design features in the target model in order to address the concerns of low liquidity in the Southern Hub capacity market. Many of these features are commonly used in developed European markets for this reason.[71] Indeed, these features should make it easier to dynamically trade entry and exit capacity than it is for AMDQ in the current market. For example:

- Market participants would not be required to purchase exit capacity to distribution networks, but would instead be allocated it. For example, a new retailer without a GSA and servicing distribution connected customers would only have to source gas through the Southern Hub exchange and nominate withdrawals. It would not need to purchase entry capacity (as it is not injecting any gas to the Southern Hub), nor purchase exit capacity (as this is allocated). There could be no risk of competitors hoarding capacity or exercising market power at these points.

- The use of auctions to allocate capacity allows parties equal opportunity to bid for baseline and above baseline capacity, and for capacity to be allocated to the participant who values it most. Some capacity would be held back for shorter term sales, so capacity would be continually offered to the market.

- Secondary trading of capacity would be allowed through bilateral arrangements or facilitated through an exchange. In addition, contracted but un-nominated capacity would be offered to the market through a day-ahead auction (use-it-or-lose-it).

Collectively, the Commission expects these design features to allow ready access to appropriately priced entry and exit capacity.

69 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, p. 34.

70 For example, see: AGL, Submission to the March discussion paper, pp. 3-4; AEMO, Submission to the March discussion paper, p. 1.

71 For example, pipelines from 16 countries use the PRISMA capacity trading platform for primary and secondary capacity sales. See: https://corporate.prisma-capacity.eu/about-us/, accessed 13 October 2016. The Network Code on Capacity Allocation Mechanisms defines harmonised capacity allocation mechanisms for cross border interconnection points between member states. ACER, *Network Code on Capacity Allocation Mechanisms*, 17 September 2012.

3.3.3 Costs of the Southern Hub

Through the working group process, some stakeholders have expressed concerns that the Southern Hub model may be unduly costly,[72] and that the amount of change involved might be unnecessary.[73] While many of these stakeholders consider that some reform of the DWGM is warranted, they have suggested that incremental changes may be more appropriate.[74]

The Commission notes that, in September 2015, it consulted on a range of potential DWGM reforms, including a package of incremental changes. This package was primarily comprised of measures to better facilitate the allocation and trading of AMDQ rights, as well as a "targeted transmission rights" mechanism that aimed to (partially) address the current free-rider investment issue. However, the Commission ultimately concluded that the multiple schemes proposed under this package would significantly increase the complexity of the current market arrangements, while delivering only modest improvements in participants' ability to manage risk and in investment incentives.[75]

The Commission understands that some of the incremental changes now being considered by stakeholders include measures that seek to introduce exchange-based trading, either on a forward basis in the DWGM or as a physical hub at Longford, and to have congestion "built-out", as well as to augment AMDQ rights. Although some of these concepts were not included in the September 2015 Discussion Paper, the Commission remains concerned that incremental reform would be likely to add complexity to the current market design for little benefit and, unlike the Southern Hub model, would not be capable of achieving the Council's Vision.

In particular, the Commission is unconvinced that adding exchange-based trading to the DWGM on a forward basis would be notably more successful than the current ASX derivative product[76] or would lead to a significant change in trading behaviour by participants. Alternatively, creating an exchange for physical trading at Longford would be likely to reduce the transaction costs associated with the secondary trading of gas there but trading would, by definition, be less liquid than at hub that covered the entire DTS. Finally, the Commission does not support building-out all congestion - the efficient cost of congestion is not zero. The challenge is to develop market arrangements that result in a workably efficient balance of congestion and investment, and allocate the associated risks to the parties best able to bear them.

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72 AEMC, Review of the Victorian Declared Wholesale Gas Market, Working Group Meeting 1, Summary of Discussion.

73 AEMC, Review of the Victorian Declared Wholesale Gas Market, Working Group Meeting 4, Summary of Discussion.

74 AEMC, Review of the Victorian Declared Wholesale Gas Market, Working Group Meetings 3 and 4, Summaries of Discussion.

75 AEMC, Review of the Victorian Declared Wholesale Gas Market, *Draft Report*, 4 December 2005, pp. 58, 62.

76 Any product sold through such a DWGM-based exchange would be a financial derivative.

The Commission also notes that some concepts raised by stakeholders go beyond what could reasonably be characterised as incremental reform, being based around nodal or zonal pricing and financial transmission rights.[77] The Commission consulted on a model of zonal prices and financial transmission rights in the September 2015 Discussion Paper. While the Commission concluded that such a model may have some benefits (in terms of "cleaner" energy prices and signals for inter-zonal investment), it would also have some drawbacks (multiple locational, as well as temporal, prices and a lack of signals for intra-zonal investment).[78] More generally, the Commission notes that nodal pricing appears untested in gas markets anywhere in the world, whereas the Southern Hub model is based on the standard entry-exit model applied throughout Europe.

While the Commission acknowledges stakeholder concern regarding the likely implementation costs associated with a move to the Southern Hub model, the cost-benefit analysis undertaken by PwC indicates that these costs would be significantly outweighed by the likely benefits. However, the Commission continues to be interested in stakeholder views on this matter and encourages all stakeholders considering potential alternative reform options to provide these through a formal submission.

3.4 Implementing the Southern Hub

The analysis undertaken by the Commission in a review is typically broad in nature and is often intended to assist the COAG Energy Council in the design of a policy approach. In this review, the Commission has assessed a range of options to improve and reform the DWGM, and has identified the option it considers best promotes the Energy Council's Vision and the NGO. Consistent with most reviews undertaken by the Commission, this review has not considered all design details that will have to be finalised prior to implementing the Southern Hub.[79]

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

Implementing the reforms required to meet the Energy Council Vision is a significant undertaking given the breadth and scale of changes that will be necessary over the next

77 AEMC, Review of the Victorian Declared Wholesale Gas Market, Working Group Meetings 1 and 3, Summaries of Discussion.

78 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, 4 December 2005, pp. 58, 62.

79 'Implementation' of the Southern Hub is a different topic to 'transition': transition refers to the transitional arrangements that could be applied to help market participants adjust (or transition) to the Southern Hub model; while implementation refers to the process for the COAG Energy Council, energy market bodies and industry members to further develop and decide to proceed with the Southern Hub model.

decade. The reforms require changes to the NGL, Regulations, NGR and industry practices and procedures and must be thoroughly assessed and appropriately sequenced. This will require full-time and dedicated resourcing as well as a significant commitment from industry and relevant institutions.

The Commission therefore considers that more direct industry and consumer involvement is required before moving to the rule change process for a Southern Hub. The specific design of the reforms is likely to be relatively broad in scope and involve significant complexity. Industry participants have the requisite knowledge to develop a detailed market design with proportionate and effective implementation arrangements.

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

3.4.1 Implementation for the Pipeline and Wholesale market reforms

The East Coast Review recommended a suite of reforms related to wholesale markets and pipeline capacity trading. It recommended that COAG Energy Council establish a dedicated Gas Reform Group to develop the package of changes to the NGL, NGR and any subordinate instruments to implement the recommendations related to wholesale markets and pipeline capacity trading.[80]

In August 2016 the COAG Energy Council agreed to establish a time limited Gas Market Reform Group (GMRG). The GMRG would have an independent chairperson to facilitate technical working groups with industry members to design and develop technical solutions to reform measures, supported by a project manager, senior technical advisor and secretariat staff functions.

Dr Michael Vertigan was appointed the chairperson of the GMRG and will be responsible for appointing the project management office and deciding on the form of and terms of reference for technical working groups. This is expected to be set up by the end of 2016.

3.4.2 Implementing the Southern Hub

Recommendation 5: The COAG Energy Council should task the Gas Market Reform Group (GMRG) to implement the Commission's recommended reforms to the DWGM (Recommendations 1-4) and the corresponding required design features. The GMRG should also take into account any preferred and suggested elements outlined by the Commission.

80 AEMC 2016, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 Final Report, 23 May 2016, Chapter 3.

Gas Market Reform Group to further develop the Southern Hub

Consistent with the Commission's recommendation in the East Coast Review for the implementation of wholesale market reforms, the Commission considers it appropriate that the Southern Hub arrangements be developed and implemented by the GMRG.

The Commission further considers it important that a single body, rather than multiple bodies, be tasked with designing the detail of reforms across the DWGM Review and East Coast Review. A single body would be better able to understand the interlinkages between the reforms and enable the package as a whole to be developed in an internally consistent manner. Some of the benefits of the Southern Hub would stem from building consistencies with a Northern Hub that facilitate trading across the east coast.

The GMRG has been established to design and implement gas market reform measures at the strategic policy direction of the COAG Energy Council. The Commission recommends that the DWGM reforms (outlined in this report and the attached technical report) form part of the work to be progressed by the GMRG.

Strong industry involvement in the reform outcomes, through the GMRG, will help to build industry ownership of the reforms. However, it will be important for SCO and/or the Victorian Government to provide strong leadership and direction to the technical working group tasked to develop the Southern Hub model further, given the breadth of the changes involved and the benefits that would accrue to the whole east coast market from the reforms. The Commission recommends that several jurisdictional representatives be included in the working group to assure the COAG Energy Council that the policy objectives are being met (as opposed to making decisions on the specifics of implementation).

A summary of the GMRG with regard to the Southern Hub implementation is provided in Figure 3.2 below.

Required, preferred and suggested outcomes

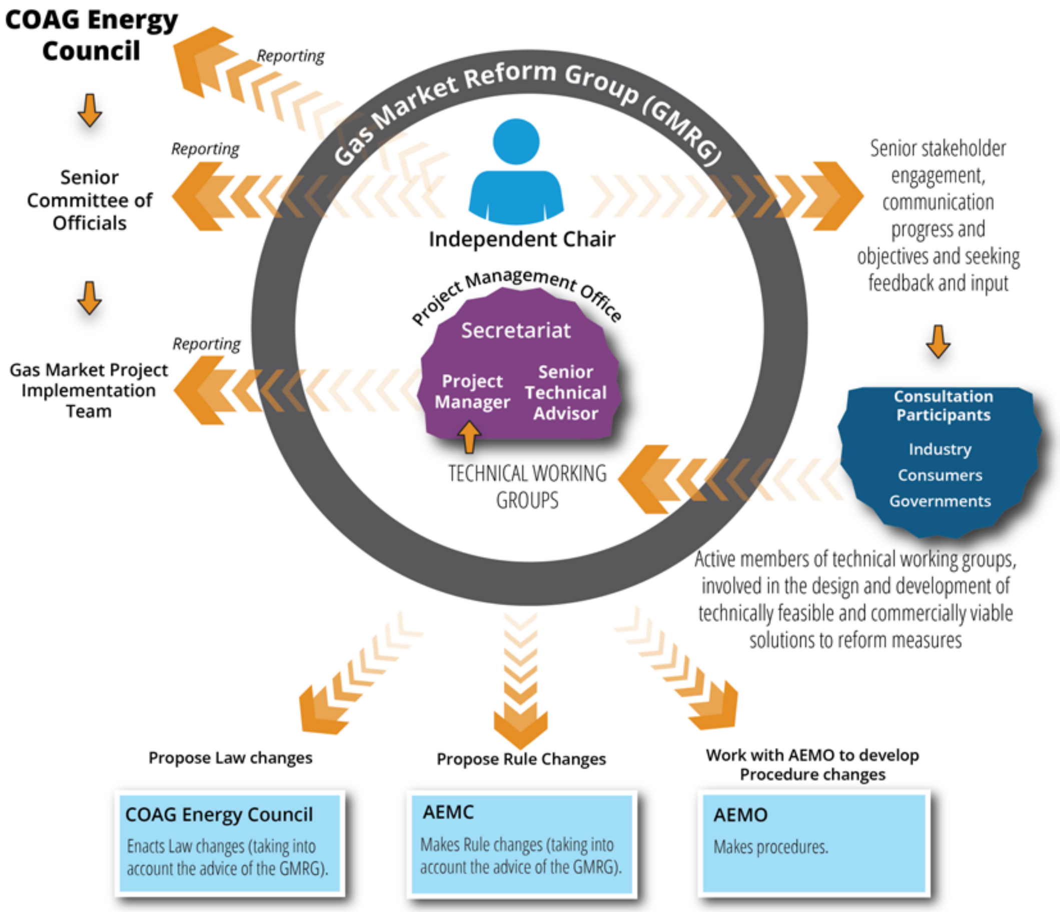
As part of this review, the Commission has identified various outcomes that might be pursued for each of the components of the package of reforms. Where the Commission considers that a particular recommendation is necessary for the overall reform to be effective, this has been reflected as a **required**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

- In some of these cases, the Commission has highlighted its **preferred** outcome which the Commission recommends the GMRG should pursue unless it is clear that there are greater benefits in alternative approaches. The GMRG should be required to have a strong rationale to depart from implementing a preferred outcome.

- In other cases the Commission has **suggested** the most appropriate outcome given the in-principle benefits that may arise from its implementation, which the GMRG should consider in its analysis.

"Required", "preferred" and "suggested" outcomes have been identified in Appendix D and in the associated technical report.

Figure 3.2 Gas Market Reform Group



Market trials to refine the Southern Hub model

The Commission recommends that the GMRG undertake extensive and detailed market trials of both the target model and transitional measures. This would have a number of benefits including:

- identifying any problems in the design of the target model and transitional measures, and allowing these to be addressed as appropriate;
- educating market participants and other stakeholders about the Southern Hub, including preparing them for market start; and
- establishing the likely emergence of liquidity in the commodity market in the target model and transitionally.

Market participants, the system operator, and potentially other stakeholders would collectively "play-out" various scenarios (without any physical gas flowing or cash changing hands) in real-time or in accelerated time, with the goal of "maximising profit" (as would have been the case had the trial been real). Scenarios would have to be varied and unpredictable, such as benign summer days or high demand winter periods.

Meaningful market trials would be a considerable undertaking, and as such, inconsistent with the time available in this review. At their most sophisticated, these trials may involve a complete build of the Southern Hub IT systems, including but not limited to:

- dummy load-flow modelling of the physical gas system;
- nomination and validation systems;
- the commodity exchange;
- the capacity exchange;
- IT systems that track system and individual balancing; and
- settlement.

Less sophisticated trials could test certain elements of the Southern Hub model in isolation from others.

These trials could be undertaken over the course of a number of months, with multiple iterations of the target model and/or transitional design being progressively refined based on the findings of previous trials. For the trials to be meaningful, a material amount of time and commitment from market participants and other parties would be required.

However, the trials could never fully replicate the actual behaviour of market participants in any given scenario. Even in the most sophisticated trial, which includes the full design of the Southern Hub, no real money would change hands and this would have the potential to distort behaviours. Nevertheless, the Commission considers that the exercise would be valuable, informed by the market trials run in the development of the National Electricity Market in the 1990s.

3.4.3 NGL and other changes to give effect to the reforms

The task of the GMRG would be to propose the details of recommended NGL changes to the COAG Energy Council and details of recommended NGR changes to the AEMC[81] to effect the detailed design of the recommended reform package.[82] It would

81 The GMRG will be able to submit a rule change request to the AEMC once the South Australian Parliament has amended the NGL to allow parties other than AEMO and Ministers of adoptive jurisdictions to propose changes to the NGR related to the DWGM.

also work with AEMO to identify changes to subordinate documents, such as AEMO procedures, that it recommends be created or amended under the NGR.

The GMRG would propose NGL changes to the COAG Energy Council and NGR changes to the AEMC to implement the reforms. It would also work closely with AEMO to identify whether procedures need to be made or amended.

The Commission has considered the changes to the NGL, NGR and subordinate instruments that may be required to implement the Southern Hub.

It is envisaged that the current regulatory framework could be used to implement the Southern Hub:

- Part 22 of the NGR (Gas Trading Exchange) would apply to market participants using Southern Hub based exchange products and is likely to require minimal changes. Parties could trade using the exchange or outside the exchange.
- Part 19 of the NGR (DWGM Rules) would be completely revised to include the new requirements related to capacity and balancing. This new Part 19 would apply to market participants in parallel to Part 22, as market participants would be required to comply with these provisions regardless of whether they are trading using the exchange or bilaterally.[83]
- Parts 8-12 of the NGR (economic regulation of pipelines) would continue to apply to the DTS. Some minor changes may be required to support specific aspects of the Southern Hub model.[84]
- A version of the Service Envelope Agreement between APA as the DTS owner and AEMO as the DTS operator would continue to apply.[85]

As a consequence of retaining the existing regulatory structure, major changes to the NGL appear unlikely. However, some may be required to the extent that any functions and roles change and to manage the transition from AMDQ to the entry-exit model for capacity.

Any NGL and NGR changes and subordinate instruments required will depend on the detailed design of the reforms, which will only be known once the GMRG's analysis has progressed.

In many cases, the GMRG may recommend that detailed arrangements are not contained in the NGR, but instead in subordinate instruments. This is a common

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82 The South Australian Minister responsible for energy can be given the power to make rules by way of a change to the NGL, as under sections 294 to 294E. Therefore, the NGL and NGR amendments could be implemented as a package through the South Australian Parliament, to the extent this is necessary.

83 All trades would be notified to AEMO as the system operator.

84 Potential changes are discussed further in Chapter 6.

85 Under the Service Envelope Agreement the pipeline operator provides a single service (the reference service) to AEMO, which is the only user of the pipeline under the NGL definition. Shippers access the reference service through AEMO in accordance with the NGL and NGR, with the only relationship between the pipeline operator and shippers being through the transmission payment deed.

approach taken in both the NGR and National Electricity Rules (NER). In these cases the NGR might contain overarching design features and principles, and instruct another body to be responsible for the detail through the subordinate instrument. Such subordinate instruments are likely to include:

- AEMO procedures;
- the Service Envelope Agreement; and
- the DTS service provider access arrangement.

3.4.4 Assessing the development of reforms

In the East Coast Review the Commission recommended, and COAG Energy Council agreed, that the AEMC be tasked to provide a biennial report on growth in liquidity in wholesale gas and pipeline capacity trading markets.

The first report is due to be provided to the COAG Energy Council by mid-2018. While a terms of reference is yet to be received, the Commission recommended that the first report could primarily cover how trading is developing through the GSH, as well as updating Energy Ministers on how the market is adjusting to the structural changes underway.

Subsequent reports could measure the development in gas trading and capacity trading at the Southern Hub, once those reforms have been implemented. Such reports could be used to identify whether transitional arrangements should be removed (see Chapter 7).

3.4.5 Implementation as part of a broader package

In the East Coast Review, the Commission recommended a staged approach to implementing the reforms to the Natural Gas Services Bulletin Board, pipeline capacity trading, and wholesale markets. In this way, the Commission envisaged that the implementation of the complete package would occur over several phases, forming a roadmap to guide the development of the market over the next decade.

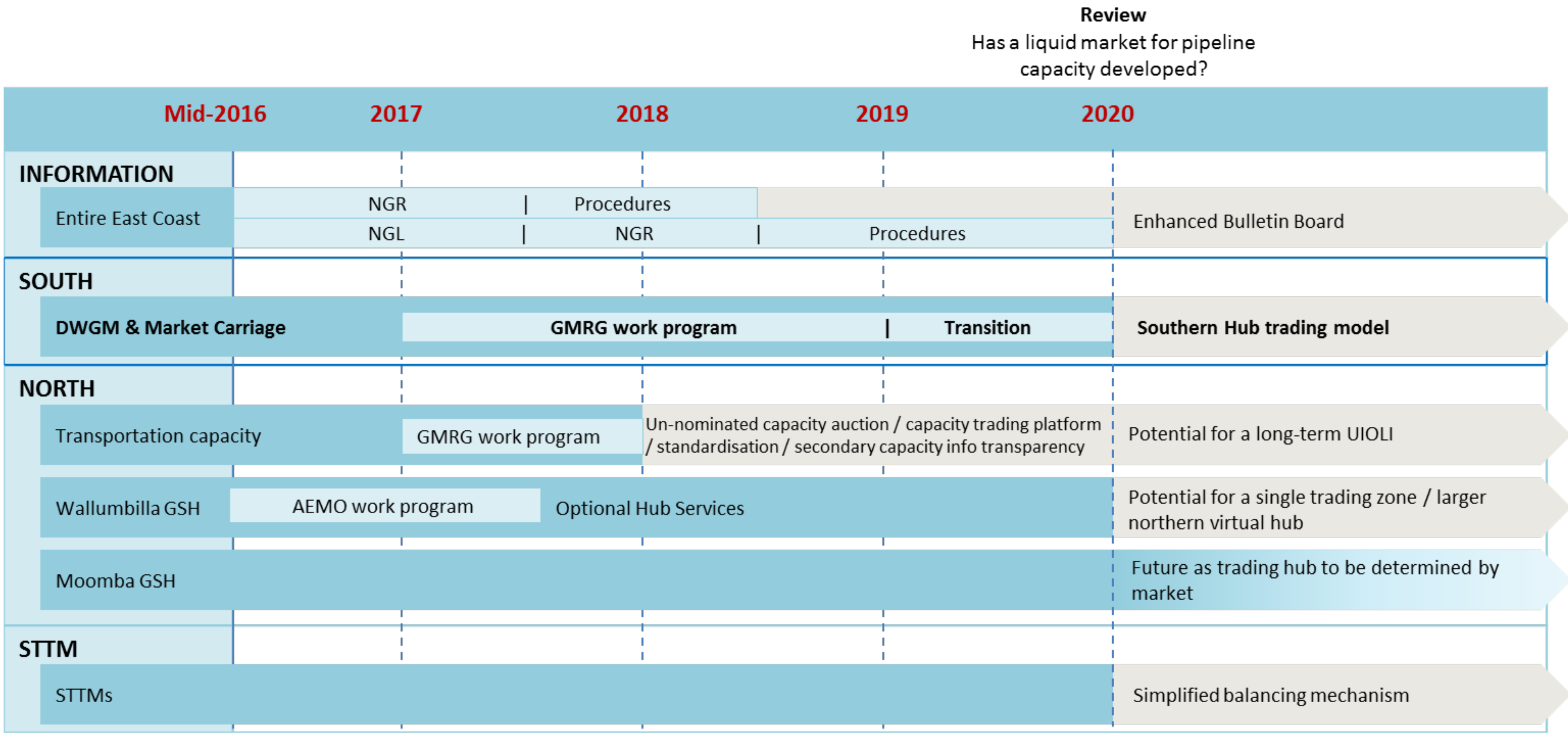
The COAG Energy Council has already commenced work on the first phase of work for several of the workstreams from the East Coast Review. It is preparing to make changes to the NGL and NGR (drafting a rule change request) to reform the Bulletin Board. Once set up, the GMRG will drive the work program on pipeline capacity and wholesale markets (discussed above).

The Commission's current view is that implementation of the Southern Hub would occur during the first phase of reform, to be completed within the next five years.

As discussed in section 3.4.4, the AEMC will be tasked with monitoring liquidity and providing a report to the COAG Energy Council on a biennial basis. This review will provide the mechanism through which the Commission recommends when some of the staged reforms should be implemented, to be developed by the GMRG.

An overview of the staging of the overall package is set out in Figure 3.3 below.

Figure 3.3 Implementing the Southern Hub



4 Commodity trading at the Southern Hub

Box 4.1 Recommendations

Recommendation 1: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.

Commodity trading under the Southern Hub model would have the following features:

1. **Capacity is sold separately to commodity**: market participants would obtain capacity through a separate mechanism to commodity sales. As a result, market participants would no longer have to bid all gas into the market to allocate capacity (scheduling) and different models for commodity trading would be possible.

2. **Commodity trading is voluntary and continuous**: market participants may trade bilaterally (through long-term contracts or OTC contracts) or through a Southern Hub trading exchange that would be similar to the Northern Hub. Trading may occur at any point in time (continuous) and a number of different products would be available through the exchange.

3. **The Southern Hub would remain a virtual hub**: all gas within the hub would be fungible and trading would occur at a 'notional point' (not a physical location). Therefore market participants would be able to trade with each other regardless of their location within the DTS (subject to having suitable capacity rights).

4. **Trading products determined in consultation with market participants**: the trading products could be based on those currently offered in the Gas Supply Hub in the first instance, but tailored to meet the needs of Southern Hub participants.

4.1 Capacity sales separated from commodity sales

In the existing DWGM (which is a 'market carriage' model) the transport of gas is implicitly bundled with the sale of gas. Market participants place bids and offers for all gas for the upcoming day, and are scheduled (granted capacity) on the basis of the outcome of those bids and offers. As such, the trading arrangements must conform with, and are limited by, the scheduling process.

Separating capacity from commodity sales would enable different models for commodity trading. There would no longer be a requirement for all gas to be bid or offered into the DWGM to facilitate scheduling. It would also mean that administratively, commodity trading is completely separated from capacity sales.

A key benefit of this separation is that market participants would be able to trade gas beyond the day or a day ahead. Being able to enter longer term trading arrangements market participants would have an additional means to manage their risk, by entering into a physical position.

This approach is also identical to the existing Gas Supply Hub design (see Box 4.2) although the nature of the capacity rights are fundamentally different (being point to point rights for the existing gas supply hub versus an entry-exit model in the Southern Hub).

The means by which capacity would be allocated to market participants is the subject of Chapter 6.

4.2 A Southern Hub in Victoria

The Commission's Recommendation 1 is that a Southern Hub[86] be established on the DTS. This would involve the introduction of exchange based trading, similar to the existing Gas Supply Hub (GSH) design (see Box 4.2), as well as changes to the other design features of the existing DWGM.

Introducing a Southern Hub that operates in a similar manner to the GSH would reduce the number of different facilitated gas markets on the east coast. This is expected to make it easier for parties transporting gas across different markets and may encourage new participants to enter the DWGM.

Box 4.2 Key features of the Gas Supply Hub

The GSH is a market design that has been implemented at Wallumbilla in Queensland and Moomba in South Australia, to facilitate upstream trading of gas. It provides a low cost and flexible method for market participants to voluntarily buy and sell gas as a complement to existing bilateral agreements.

It was also established to provide a reference price that would support a financial derivative market.

The GSH is not a virtual hub. There are currently three trading locations at Wallumbilla and two trading locations at Moomba.[87]

Trades are matched anonymously, although there is a separate mechanism that allows participants to agree bilaterally to a standardised product and then register the transaction. This can lower transaction costs, and also reduce counterparty risk.

86 Throughout this report the reformed DWGM is referred to as the 'Southern Hub' as it aims to develop a 'southern' reference price for gas.

87 Deliveries are netted each day by AEMO to minimise the number of transactions that need to be delivered. Each trading participant receives a net gas delivery obligation and is responsible for delivering gas to that location using existing contractual supply and transportation agreements.

The Southern Hub model would have the following features:

1. **Trading is voluntary**: market participants may trade bilaterally (through long term contracts or OTC contracts) or through an exchange. There would be no need for a market participant to 'trade' with itself.

2. **Trading occurs continuously**: market participants may trade at any time using a variety of products of different lengths of time.

3. **The Southern Hub would remain a virtual hub**: all gas within the hub would be fungible and trading would occur at a 'notional point' (not a physical location). Therefore market participants would be able to inject or withdraw gas at any point (subject to having sufficient capacity rights).

4. **Balancing is market-based**: market participants would be primarily responsible for balancing (by trading among themselves) and the system operator would have a residual balancing role when the system as a whole is out of balance, to maintain the system within safe operating limits (discussed in detail in Chapter 5).

This market design is referred to as 'voluntary trading with market-based balancing' since participants are not forced to make bids and offers for gas injections and withdrawals within the balancing period. Rather, they are incentivised to trade and remain in balance. In this sense, it is the market that is primarily responsible for keeping the DTS in balance.

4.3 Greater flexibility for trading

Under the new arrangements, market participants would have greater flexibility to purchase gas through three mechanisms:

- the exchange;
- bilaterally, using OTC contracts; or
- long-term GSAs.

The Southern Hub would also provide greater trading flexibility for market participants by allowing continuous trading, in which gas could be purchased through the exchange at any time. It is expected that the exchange would include a range of trading products to suit the needs of market participants in Victoria, such as products of varying lengths (as is the case in the existing GSH).

Currently the GSH offers a range of different trading products (see Box 4.3). The trading products to be offered on the Southern Hub could be based on these, but tailored to meet the specific needs of market participants. Products should be developed having regard to the physical capabilities of the DTS. For example, there is likely to be a need for shorter-term products in the Southern Hub market to meet the balancing needs of both participants and the system operator (discussed in Chapter 5).

As with the development of products for the GSH, products for the Southern Hub exchange could be easily added or removed, in consultation with market participants.

Box 4.3 Gas Supply Hub trading products

The trading products currently available through the GSH are:[88]

- monthly;
- weekly;
- daily;
- day-ahead; and
- balance of day.

These products typically require a uniform flow rate over the delivery period and a minimum parcel size of 1,000 GJ for each gas day in the delivery period (or 25 GJ/hour for the balance of day product).[89]

In addition, three physical spread products are available from Moomba to Wallumbilla.[90] These are monthly, daily and day-ahead products.

While the Commission recommends that the Southern Hub would have similar characteristics to the Northern Hub, one of the key differences would be that the Southern Hub, like the existing DWGM, would remain a virtual hub.[91]

A virtual Southern Hub means that participants trading on the exchange would only see one trading location, instead of three trading locations as is the case in Wallumbilla:

- All gas within the hub would be fungible. Market participants could inject gas at one point and withdraw from another without planning the transport of that gas between the points.
- Trading would occur at a 'notional point' and not one or more physical locations.
- Market participants would be responsible for delivering gas to the hub and withdrawing gas from the hub. They would not need to concern themselves with transporting gas between those points.

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88 Specifications for each of these trading products are located in the Gas Supply Hub Exchange Agreement, available on the AEMO website.

89 AEMO is currently considering a proposal to reduce the minimum parcel size to 100 GJ per day, except for the balance of day product. The product specifications would need to be further reviewed on implementation in the Southern Hub exchange.

90 This gives participants the option to swap gas between the trading locations.

91 Wallumbilla is currently a physical trading hub and trading is spread across three physical locations. Market participants are responsible for delivering or receipting gas at each of the locations.

- The system operator would be responsible for managing gas flows within the hub, to manage system security and ensure the delivery of gas to all market participants.

Another key difference between the proposed Southern Hub and the existing GSH is that in the Southern Hub, a party purchasing gas from the exchange would be guaranteed delivery.[92] If a counterparty to a transaction defaults on a delivery obligation to the Southern Hub, they would be incentivised to restore their balance, or be cashed out if they cannot. The hub operator would maintain balance within the network.[93]

4.4 Establishing a meaningful reference price

Price discovery would occur via the exchange initially, in that prices struck for exchange traded products would be published (as is done on a stock exchange). The exchange would also publish a volume-weighted end of day price at the Southern Hub (as is currently provided for the GSH), which financial derivative products could reference.

Financially traded products typically require a standardised underlying physical product that is commonly traded to reference. This standardisation encourages transactional efficiency and the development of liquidity. The financial gas market is directly linked to the physical gas market and usually evolves from some form of standardised contract for the sale of physical gas.

The establishment of exchange-based trading allows for innovation in products offered and for standardised products to emerge (e.g. day-ahead products, monthly products and winter 2020 products) and market forces will determine the success of individual products – that is, products will be traded only to the extent that they are useful to participants. In well-established commodity markets, financial derivatives generally reference the price in the most liquid of these products.

92 In particular, in the event that an exchange counterparty defaults on part, or all, of its delivery quantity at the Wallumbilla GSH, they are required to compensate their counterparty for 25 per cent of the value of the variation. Importantly, this compensation is the only remedy available for a breach of a participant’s delivery obligations and may under or over compensate a participant for their actual direct costs associated with the delivery default.

93 Balancing mechanisms are discussed in Chapter 5.

5 Balancing

Box 5.1 Recommendations

Recommendation 2: Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.

Balancing is an integral part of a physical gas market because injections into the system must over time equal withdrawals, and pressures must remain within operational limits to maintain system security. Balancing at the Southern Hub would be the process by which supply and demand would be adjusted to ensure that the system remains secure, with the following key design features:

Balancing would take place at the virtual hub. This would maximise liquidity as there is no defined physical location for balancing, consistent with the rationale for commodity trading more generally as discussed in Chapter 4. It would be the responsibility of the system operator to take whatever actions are needed to deliver the gas from where it enters the system to where it must exit the system.

The Southern Hub would feature a mandatory continuous balancing regime. Market participants would each have primary responsibility for their own balancing, and would have to maintain a balance between their cumulative supply and demand at those times that the system linepack becomes unacceptable. There would be financial incentives to do so, and gas could be traded at the virtual hub or sourced from a market participant's own portfolio, although all physical flows must be within the allowable capacity of the system.

The system operator would be responsible for residual balancing to maintain an appropriate system wide balance. If market participants were not collectively maintaining an acceptable balance between supply and demand despite their financial incentives, the system operator would be required to take residual balancing actions to restore an acceptable balance for the system as a whole. The costs of actions by the system operator would be recovered from those causing the need for residual balancing action.

The system operator would be responsible for undertaking a variety of other actions to maintain system security not related to system wide balancing. Situations may arise which would require action from the system operator to maintain system security which are not related to system wide balancing. For example, local linepack may be inappropriately low, even if the system wide linepack situation is within acceptable operating limits. The system operator would be responsible for undertaking actions which address these issues. It would also be able to invoke emergency management procedures.

5.1 Balancing takes place at the virtual hub

For the purposes of balancing, the virtual hub would cover the transmission system with no distinction – gas injected at all entry and gas withdrawn at all exit points would be treated as being the same once inside the hub. This means that forward commodity trading at the Southern Hub could be used for balancing purposes, with market participants who have sold commodity before the day able to decide at which entry points it would be delivered on the gas day, subject to holding sufficient entry capacity.

This flexibility of delivery is likely to improve liquidity at the Southern Hub, as market participants would not be limited to offering and delivering commodity at a specific location – they would be able to choose suitable locations from within their commodity and capacity portfolios, or reduce their own demand in one location to meet an increase in demand elsewhere.

While a virtual hub is likely to promote liquidity, it does mean that the system operator would be required to manage gas flows in the transmission system to meet demand from wherever market participants choose to supply gas. In order to enable this:

- Market participants would be required to nominate supply and demand flows to entry and exit points, so that the system operator has sufficient information to manage flows across the system (discussed in section 5.2.4).
- Market participants' nominations at entry and exit points would be expected to be consistent with their capacity rights, which in turn would be consistent with the physical capabilities of the transmission system (discussed in section 5.2.4).
- The system operator would have a suite of tools at its disposal to ensure the transmission system remains secure, including residual balancing action, other system security actions, and emergency powers of direction (discussed in sections 5.3 and 5.4).

5.2 Mandatory continuous balancing

5.2.1 Mandatory balancing

Mandatory balancing means that each market participant has primary responsibility for maintaining a balance between their own supply and demand over time. This responsibility would be bestowed through financial and regulatory incentives to encourage market participants to collectively maintain the overall system balance within system security limits. If, as a consequence of these incentives, individually all market participants were to be in balance, the system would also be in balance.

The system would be able to absorb some level of imbalance. If, however, some market participants were to be sufficiently out of balance so as to affect the security of the overall system, the system operator would need to use the suite of tools available to take action to restore system security.

Financial incentives work most effectively when there is direct link of cost to cause, but this can be complex and costly to achieve. Regulatory incentives can stifle market participants' ability to manage situations flexibly, but are useful as a last resort when financial incentives are no longer effective. The design of an incentive framework must therefore be finely tuned to manage the trade-off between effectiveness and complexity.

5.2.2 The choice for continuous balancing

Some entry-exit markets require market participants to be exactly in balance at pre-defined points in time (e.g. daily[94]) or be subject to financial penalties, in order to ensure that the system as a whole remains in balance.

The disadvantage of this approach is that market participants are frequently incentivised to be in balance (and charged for not being so) despite this not necessarily being required for system security reasons. As a result, there is less efficient use of useable system linepack at the end of the balancing period, and can mean that more expensive commodity products are needed to restore balance within a limited timeframe.

This issue is exacerbated the shorter the balancing period, and hence the more frequent the requirement for market participants to be in balance.

Conversely, long balancing periods may result in the system becoming problematically out of balance because there are no incentives on market participants to be in balance within the period. This may be particularly the case in the DTS, which has the characteristic of limited linepack.

Given these considerations, the Commission recommends an alternative, continuous balancing approach should be adopted. Under such an approach, market participants would not be required to be in balance at any pre-determined time, but would be subject to residual balancing action charges if they were out of balance at the time when residual balancing action is taken by the system operator. Consequently, market participants would be able to carry forward an imbalance at any time, including between gas days, providing the system security was not threatened.

The advantage of the continuous balancing approach is that market participants are only incentivised to be in balance when system security is threatened. Linepack is efficiently used the rest of the time, and market participants are not (necessarily) required to arrange for responses overnight when they currently have limited ability to do so.

94 For example, most European markets including the Great Britain, Belgium and Denmark have a requirement to be in balance at the end of the day.

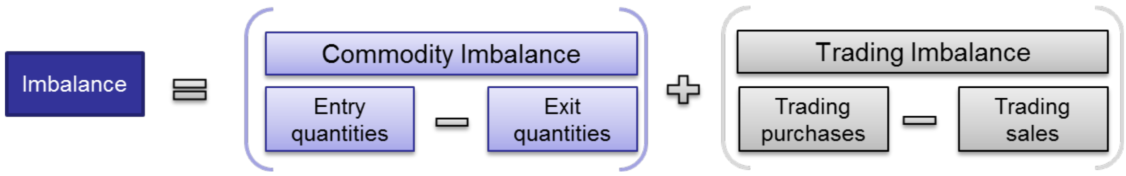
5.2.3 Matching supply and demand at the virtual hub

A market participant's imbalance would be defined as the difference between its supply and demand over a period of time. Supply would be defined as the total of entry quantities into the virtual hub plus trading purchases at the virtual hub (for which the selling market participant must increase entry quantities, reduce demand, or have sold an imbalance surplus). Conversely, demand would be defined as the total of all exit quantities from the virtual hub plus trading sales at the virtual hub.

Figure 5.1

Rearranging the above equation, this can also be thought of as the commodity imbalance plus trading imbalance over a period of time.

Figure 5.2



To be in balance, over time a market participant must match supply with demand.

5.2.4 Mandatory nomination to entry and exit points

While the system operator would know that trades have taken place at the virtual hub, it would not know on the basis of these trades the location of the physical flows resulting from the trades. To enable the system operator to securely manage physical gas flows on the virtual hub, market participants would be required to provide their expected supply and demand as hourly flows at specific entry points to and exit points from the virtual hub. This process is called nomination.

Nomination by market participants of hourly flows of gas to entry and exit points on a gas day would start ahead of the gas day, and would be timed to close after the close of forward trading. Market participants would be able to update prospective nominations (i.e. for hourly flows starting after the beginning of the next hour) at any time. For example, a market participant would be able to transfer injections from one entry point by reducing nominations of hourly flows at the original entry point, and increasing them at the new entry point.

Market participants would be expected to nominate consistent with their entry and exit rights.[95] Because the number of entry and exit rights would be consistent with the physical capability of the system, in ordinary circumstances nominations should be able to be physically accommodated.

5.2.5 Monitoring market participant imbalances

For continuous balancing to work, market participants would need to be able to monitor their imbalances as the day progresses. In the Southern Hub, this would be known as their position (abbreviated as POS).

The system operator would determine each market participant's position hourly, and publish it shortly thereafter. The actual position would be published at the end of the previous hour, and projected positions for upcoming hours. Once an actual position is published it would not change (i.e. it is not updated retrospectively), as market participants would use this position to make decisions that manage their supply and demand.

Market participants would also need to know the overall state of the transmission system. This would allow them to choose to take corrective action if their position is significantly contributing to the cumulative imbalance and they are at risk of paying financial incentives. The cumulative imbalance is the system balance signal (abbreviated as SBS).

Market participants would be able to take action to restore their position to an acceptable imbalance by changing injections of gas from their own portfolio, changing demand at exit points or trading at the virtual hub. Alternatively, market participants would be able to choose to accept the imbalance and risk of financial impact if the system balance signal indicates that action by the system operator was unlikely, or that any actions would have a small financial impact.

To manage their position, market participants would need to be able to understand the potential for residual balancing actions, so that it could be averted if enough market participants were to adjust their supply and demand balance. Market participants would also need to know actual residual balancing actions already underway, as these would impact the SBS in the future, and so would need to be taken into account by market participants when deciding whether to take further action.

A comprehensive information suite that segregates access to confidential information would be likely to be implemented with the Southern Hub balancing model, and which could include graphical interfaces and comprehensive data files.

95 The most appropriate means to achieve this is likely to be that market participants would be prohibited from nominating in excess of their capacity rights. Alternatively, market participants could be penalised for nominating in excess of their capacity rights, such that the alternatives (purchasing capacity rights or not nominating above their rights) are generally preferable for the market participant. The GMRG should consider this matter further.

5.2.6 Determining market participant imbalance positions

A market participant's position would be determined for each hour. A relatively small number of meters (generally those for large consumers) may currently be sufficiently sophisticated for meter data to be available in this time, while for others, investment to improve meters may be justifiable.

However, because meter data for most meters is not currently available within an hour and upgrading such meters may be prohibitively expensive, an algorithm would be used to estimate the injections and withdrawals to be attributed to market participants with such meters. This is known as the **near real time allocation** (abbreviated as NRT allocation).

The choice of algorithm for near real time allocations is a trade-off between accuracy, timeliness and cost. The higher the target accuracy, the higher the volume of data to be processed. This increases processing time and cost. Much of the information likely to be needed is currently available for the DWGM, so the near real time allocation algorithm is technically feasible.

A market participant's position for an hour would be calculated as its actual position at the start of the previous hour, plus near real time entry allocations for the previous hour, less near real time exit allocations for the previous hour.

As a market participant's actual position for an hour would not be changed once published, a reconciliation process would address differences between a market participant's near real time allocations and their actual entry or exit flows after six months when retrospective transfers can no longer take place.

5.2.7 Market participant positions are carried over to next day

Continuous balancing means that market participants would be able to choose to have an imbalance carried from one gas day into the next, and the system operator would ensure that overall the transmission system remains secure. This means market participants would not have to trade gas to achieve a neutral position by the end of each balancing period – instead they could use the next gas day to restore their position by trading or using their own portfolio.

5.3 Residual balancing by system operator

If market participants were collectively out of balance to the extent that the system wide balance was to be affected, the system operator would be required to take action to ensure the system remains secure. This would be a transparent process by which the system operator would take action to purchase or sell gas at the virtual hub to restore system wide security. This is known as residual balancing action (RBA).

The residual balancing process would include defining the linepack limits at which the system is secure over the gas day, monitoring the state of the system against those limits, taking targeted action when the limits are exceeded and reporting to market participants.

5.3.1 Residual balancing bands

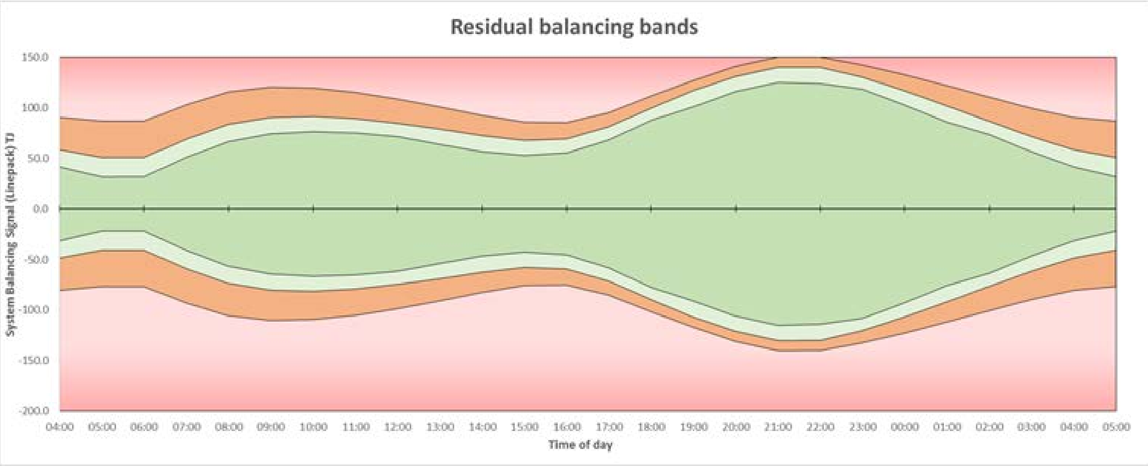
The system operator would define the linepack limits at which they would take residual balancing action. These are known as **residual balancing bands** (abbreviated to RBB).

Setting the limits is a trade-off between the system operator taking action unnecessarily early, when market participants would have individually resolved their own out of balance positions, and too late, when residual balancing costs may be higher than they would otherwise have been. Residual balancing bands would be defined before the start of the day to provide market participants sufficiently timely information to manage their balancing actions, and would be likely to be based on a number of factors such as the physical capability of the system on the day.

Residual balancing bands could cover progressive, predefined actions for system operator to do nothing, take action by buying or selling gas at the virtual hub, or directing market participants to take action as a last resort. The rationale behind the continuous balancing model is that the most likely system operator action would be 'do nothing' – it is only when the system is becoming less secure that further action would be taken.

An illustrative example of residual balancing bands is provided in Figure 5.3.

Figure 5.3 Residual Balancing Bands



5.3.2 System Balance Signal

To decide what action needs to be taken, the system operator would need to know the system's available linepack.[96] This is known as the system balance signal (SBS), introduced in section 5.2.5 in the context of market participants deciding whether to take balancing action.

The system balance signal would either be an actual system balance signal (for an hour), or a projected system balance signal (for subsequent hours).

The system balance signal would then be compared with the residual balancing bands to determine if the system operator needs to take action. As noted in section 5.2.5, the system balance signal would need to be published to market participants, who would compare it with their own published position to determine the likelihood of residual balancing action, and their likely share of any residual balancing action costs, so they can monitor the effectiveness of their own continuous balancing actions and adjust them if necessary.

5.3.3 Residual balancing action by system operator

The system operator would need to take residual balancing action if market participants collectively were not to have maintained the overall system balance within necessary limits. This would happen when the system balance signal moves beyond the 'do nothing' band.

The need for residual balancing action at a given time could be determined based on the actual system balance signal at the time, or on the projected system balance signal. The time taken by gas to move from entry points (other than Dandenong) to the major exit points in the DTS might imply a need to base residual balancing actions on the system balance signal projected forward by a number of hours. However, it may be possible to use the actual system balance signal or a shorter-term projection if the system balance bands were set on a tighter basis to reflect the added uncertainty. The detailed design phase should assess the relative merit of these approaches.

The quantity of a given residual balancing action would be set to recover the system balance signal to the extremity of the next most satisfactory residual balancing band. When taking residual balancing action, the system operator would be required to buy or sell linepack at the virtual hub using the exchange. For instance, when the system balance signal moves beyond the 'do nothing' limit, the system operator might be required to enter into a balance of day trade (or trades), through the exchange, sufficient to restore the system balance signal back to that limit by the end of the gas day. This is illustrated in Figure 5.4.

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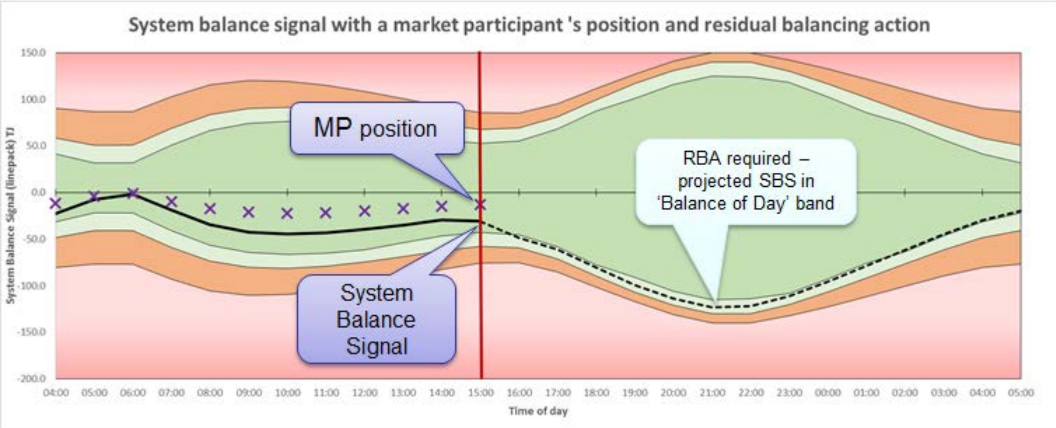
96 Using the system's available linepack for this purpose would be appropriate as some of the total linepack (calculated based on pipeline size, pressures and energy content of the gas) cannot be used for operational reasons.

Figure 5.4 Example of RBA action when SBS is projected to leave 'no action' band



By using the exchange, liquidity in the intra-day balancing market would not be diluted by using a separate, system operator specific trading platform or product as has been used in other markets,[97] and those offers/bids would remain available for participants to enter into in order to maintain their own individual position.

5.3.4 Cost recovery for residual balancing actions

The total costs incurred by the system operator for each residual balancing action would be recovered from those market participants who are out of balance (in the same direction that the system is out of balance) at the specific time that residual balancing action is taken, such that they have contributed to the need take action. These market participants would be charged in proportion to the extent to which they are out of balance. Residual balancing action costs would not be recovered from those market participants who are out of balance in the opposite direction to the system (i.e. are long of gas when the system is short, or vice versa).

Costs would be recovered from causers on an average cost basis - that is to say that the imbalance charges levied by AEMO would perfectly recover the costs associated with trades entered into on the exchange. Many European markets use marginal or penal prices in this "cash-out" process to provide a stronger incentive on participants to self-balance, and the Commission recommends that the detailed design phase further examines this trade-off.

The market participants allocated a portion of the costs of a residual balancing action would also be allocated a proportional quantity of the gas bought or sold as a trading purchase or sale – in other words, this would be counted in their imbalance in subsequent hours as the gas flows, improving their balancing position.

97 The Netherlands balancing regime initially featured a separate bid ladder for residual balancing actions, but this has now been replaced with title trading products at the virtual hub.

5.4 Other actions to maintain system security

The balancing regime described in this chapter seeks to allocate costs to market participants who, by being out of balance, cause the system as a whole to be out of balance such that the system operator needs to take residual balancing action. In doing so, it would incentivise market participants to individually remain sufficiently in balance, so that collectively the system as a whole is sufficiently in balance such that system security was not threatened.

However, maintaining system wide balance would not be the only system security consideration for the system operator. For example, linepack at a specific location in the system might approach becoming inappropriately out of balance, even if the SBS was within the 'do nothing' balancing band. This could arise, for example, because market participants change their nominations without sufficient warning for the system operator to adjust flows within the system, or because market participants fail to inject or withdraw in accordance with their nominations.

In these instances, the system operator may need to take a variety of system security actions, such as:

- buying or selling gas through the exchange at specific locations (e.g. from the Dandenong liquefied natural gas facility) which can address local linepack issues; and
- through a market process, buying back capacity rights from market participants, so that they reduce their injections at that location.

While appropriate in certain specific circumstances, these actions would be undesirable for returning system wide linepack to the do-nothing band because they might not be the cheapest option available to the system operator to resolve system wide linepack issues.

As a general principle, the costs of actions undertaken by the system operator to maintain system security should be recovered from those market participants causing the issue. This provides incentives on market participants to manage balancing in accordance with the physical requirements of the system. In the existing DWGM, these costs are recovered as surprise uplift and congestion uplift charges, with any un-attributable costs being recovered as common uplift.

Under the Southern Hub arrangements, congestion uplift would largely be replaced by the system of entry and exit rights: the baseline level of capacity released (described in Chapter 6) should not commonly cause congestion to arise because firm baseline capacity rights would be allocated consistent with the underlying physical capacity of the system, and above baseline capacity rights would be released on an interruptible basis.[98] In addition, proceeds from the sale of above baseline capacity, overrun charges received from participants and the proceeds of any financial incentives on the DTS

98 There would be no costs associated with curtailing interruptible capacity.

service provider to make baseline capacity available could all be used to fund system operator actions to manage specific system security issues.

However, the 'target' model described in this report does not currently contain any charging mechanism equivalent to surprise uplift in the current market. There is a trade-off between cost-to-cause and complexity. The more costs are accurately allocated between market participants, the more complex the design and more costly the required market systems.

The Commission recommends the GMRG, in undertaking further design work and market trials, should examine the likely magnitude of costs associated with the short-term variation of nominations, and consider whether it would be preferable to socialise these costs or design and implement a further charging mechanism to allocate these 'surprise' costs to causers.

5.4.1 Emergency management

Emergency situations on the transmission pipeline, at connection points and at connected facilities that impact on the system operator’s ability to maintain system security may arise from time-to-time. In these situations, the residual balancing action of the system operator or the other actions to maintain system security described above may be inappropriate tools to maintain system security.

In these situations, the system operator would be able to invoke emergency management procedures and direct market participants in order to maintain system security in a similar manner to the current DWGM arrangements.

6 Pipeline capacity

Box 6.1 Recommendations

Recommendation 3: The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.

Capacity trading under the Southern Hub model would have the following features:

1. **Determination of the amount of baseline capacity to be released:** carried out through a transparent process, with the pipeline operator proposing the level of baseline capacity and the AER approving such level after consultation with industry participants.

2. **Standardised capacity products:** to facilitate trade in both primary and secondary capacity that best meet the needs of market participants.

3. **Primary baseline capacity to be allocated:**

   (a) at distribution connected exit points, using a dynamic allocation mechanism; and

   (b) at all other entry and exit points, through the use of short and long term auctions.

4. **Above baseline capacity:** released through a day-ahead and/or within day auction, with capacity rights to be offered on an interruptible basis.

5. **Measures to encourage the release of secondary capacity:**

   (a) a short-term use-it-or-lose-it (UIOLI) mechanism for contracted but un-nominated baseline capacity at points with contractual congestion, which would be released to the market through a day-ahead auction after a specified nomination cut-off time; and

   (b) the development of an electronic exchange that would enable market participants to trade secondary capacity on an anonymous basis.

6. **Investment in new baseline capacity:** at distribution connected exit points should be signalled through the existing bilateral planning process. At other points expansions should, where feasible, be signalled through a market-based mechanism, with the Commission's preferred mechanism being the hybrid open-season integrated auction.

To give effect to various aspects of the entry-exit model, a number of changes would need to be made to the economic regulatory framework in the NGR and, potentially, the NGL.

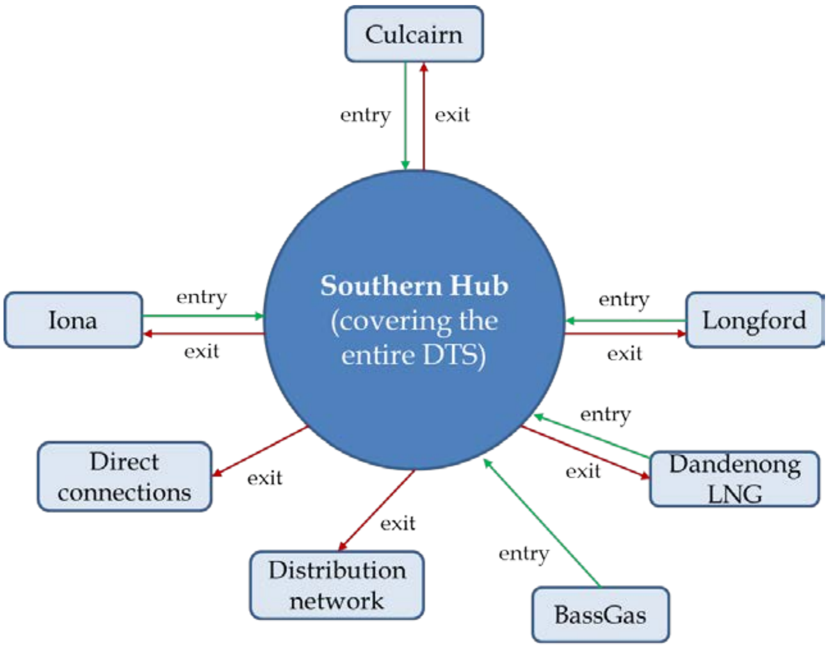
6.1 Introduction and context

To support the new form of trading and balancing that would occur under the Southern Hub model and facilitate market-led investment in the DTS, the Commission is recommending that the market carriage model and limited transportation rights[99] in the DTS be replaced with explicit and tradeable capacity rights for entry and exit to the DTS.

The entry-exit system, which is widely used throughout Europe, would allow market participants to obtain firm and interruptible capacity rights independently at entry and exit points in the system through transparent and non-discriminatory capacity release mechanisms. Specifically, a market participant would be able to acquire capacity on a firm basis (baseline capacity), which the pipeline operator would be responsible for making available. It may also be able to enter into a secondary trade with another participant. If all the baseline capacity is sold, the market participant may be able to acquire capacity on an interruptible basis from 'above baseline' capacity, which AEMO, as system operator, would be responsible for releasing.

The figure below provides a stylised representation of the entry and exit points in the DTS.

Figure 6.1 Southern Hub entry and exit points



The Commission expects the movement to this new system of capacity rights to:

- allow for the trading of forward physical products through the Southern Hub, providing market participants alternative approaches to better manage their risk (see chapter 4);

99 Authorised maximum daily quantity (AMDQ) and AMDQ credit certificates.

- enable pipeline capacity to be allocated in an efficient, transparent and non-discriminatory manner;
- promote more timely and efficient market-led investment throughout most of the DTS; and
- continue to provide for the efficient operation of the DTS.

Before this new system can be implemented, decisions would need to be made about:

- how the level of baseline and above of capacity would be determined;
- the capacity products to be made available for sale at each entry and exit point;
- how baseline and above baseline capacity would be allocated amongst market participants and how secondary trading would be encouraged;
- how investment in new baseline capacity would be signalled and allocated; and
- what, if any changes, need to be made to the economic regulatory framework to accommodate the change.

The Commission's recommendations on these key elements of the entry-exit system (**required** outcomes) are set out below. Further detail on these elements of the proposed entry-exit system can be found in the Technical Report. The Technical Report also highlights the Commission's:

- **preferred** outcomes, which the GMRG should pursue unless it is clear that there are greater benefits in alternative approaches; and
- **suggested** outcomes, which should be considered by the GMRG given the in-principle benefits that may arise from their implementation.

6.2 Calculation of amount of capacity to be released

A capacity right under the entry-exit system provides market participants with a right to inject or withdraw gas at specific entry or exit point. Clearly, to exercise this right, the amount of capacity available must be consistent with the physical capacity of the DTS.

The DTS is a complex, meshed network. Consequently, the amount of capacity physically available at each entry and exit point varies on a day-to-day basis, in response to a number of factors, such as: pipeline infrastructure, system wide and local linepack, operating considerations, such as maintenance and outages, and demand location and the profile of demand.

The nature of many of these factors means that it is difficult to accurately forecast, well in advance, the amount of capacity that would be physically available. For example, demand for gas in the DTS is a function of the weather. Consequently, even though the amount of capacity available can be forecast with reasonable certainty immediately before the gas day, the further ahead the capacity level is forecast, the greater the uncertainty.

Given this uncertainty, determining the appropriate amount of capacity rights to be released involves the following trade-offs:

- issuing more rights than are physically available (which means they cannot all be simultaneously honoured) and issuing less rights than are physically available (which risks under-utilising the network); and
- issuing rights too early (which risks allocating an inappropriate amount of rights based on inaccurate forecasts - either too many or too few) and issuing rights too late (which risks market participants being unable to plan on the basis of, and is unlikely to engender long-term market led investment).

In order to address these trade-offs, the Commission is recommending that:

- an amount of capacity that is highly likely to be physically available, regardless of the circumstance, be calculated and released well ahead of time (e.g. over the 5 year period of an access arrangement). This provides market participants with early access to capacity. Because of the high degree of confidence that the capacity would be physically available, this capacity should be released on a firm basis, providing market participants with confidence that they are unlikely to be constrained (and with financial compensation in the event of a constraint). Capacity released in this manner is known as “baseline” capacity; and
- additional capacity be released on a day-ahead basis, based on more accurate forecasts at that time of physically available capacity. This mitigates against the network being under-utilised. Capacity released in this manner would be done so on an interruptible basis and is known as “above baseline” capacity.

The Commission recommends a transparent process be employed to determine the amount of baseline capacity to be released, with the pipeline operator proposing the level of baseline capacity and the AER approving such level after consultation with industry participants, including AEMO.

The Commission envisages that this process would occur as part of the Access Arrangement review process because the setting of the baseline capacity would have important implications for other aspects of the AER’s regulatory decision-making, including:

- defining the maximum capacity that can be sold and the revenue requirement recovered from;
- future investment decisions, because if baseline capacity is set too low the market may demand further expansions to enable them to obtain firm rights; and

- any incentive scheme that the AER may decide to introduce to encourage the DTS service provider to make baseline capacity available.

The amount of baseline capacity would ideally be measured with the aid of load flow modelling software, taking into account the various factors mentioned above, with reference to a pre-defined probabilistic standard for whether the capacity is physically available. For example, capacity could be calculated and released with a probability that it could not be physically met one day in every twenty years. It is worth noting in this context that this approach is similar to the approach that is currently used to determine the availability of AMDQ and AMDQ cc.

Similar software would be used to calculate the amount of additional capacity to be released (above the baseline) on a day-ahead basis, once there is more clarity and certainty on the factors that influence the amount of physically available capacity, including the nominations of firm capacity for the gas day. The Commission recommends AEMO be responsible for such activity, because as system operator it has the best knowledge of the expected pattern of flows and operational constraints on the network each gas day.

6.3 Capacity products

Once the amount of capacity rights to be made available for sale is determined, the next step is to define what products would be available for sale at each entry or exit point.

There are a number of dimensions that need to be considered when designing entry and exit products, including:

- the firmness of the service / capacity product (i.e. firm or interruptible);
- the entry and exit points at which capacity would be made available and the extent to which any point can be aggregated into zones to facilitate capacity trading;
- the contract tenor (e.g. quarterly, monthly, weekly, day-ahead or within-day);
- the capacity metric (e.g. daily or hourly);
- the extent to which renomination rights should be allowed; and
- the operational, prudential and other contract provisions that govern the relationship between parties.

While in principle these product dimensions could be tailored to meet the needs of individual market participants, bespoke products would be less fungible and therefore more difficult to trade. Given the adverse effects this could have on liquidity in the Southern Hub, the efficient utilisation of the DTS and the ability of parties to manage their transportation costs and risks, the Commission recommends that:

- standardised capacity products be developed by the GMRG, in consultation with market participants, having regard to the required, preferred and suggested recommendations set out in the Technical Report; and
- to the extent it is relevant, that the standardised products mirror the commodity products to be traded through the Southern Hub.

6.4 Capacity allocation and release mechanisms

Under the proposed entry-exit system, entry and exit products would be made available to the market on a transparent and non-discriminatory basis through the release of:

- existing baseline capacity, which would be made available at regular intervals under both short and longer-term timeframes; and
- above baseline capacity, which would be made available on a day-ahead or within day basis once all the baseline capacity at a point has been sold to enable as much capacity to be released to the market and to maximise the utilisation of the system.

Market participants would also be able to enter into secondary capacity trades with other parties that have spare capacity. They may additionally be able to secure capacity at contractually congested points through a day-ahead auction of contracted but un-nominated capacity.

Further detail on the capacity release mechanisms that the Commission recommends be employed under the entry-exit system is provided below. Before moving on though, it is worth noting that while the Commission is recommending a number of different release mechanisms, it would expect all primary capacity be sold through the same platform. Ideally, this would be the same platform as used for secondary capacity trading and for trading gas, so that market participants can acquire gas and capacity through a single platform.

6.4.1 Allocation of existing baseline capacity

The Commission recommends that baseline capacity be released and allocated through:

- an auction in those circumstances where parties can adjust their demand in response to price because a well-designed auction would result in the most efficient allocation of capacity (i.e. because it uses price to allocate capacity to those that value it most highly) – the points in the DTS that satisfy this criterion include production entry points, interconnection entry and exit points, storage entry and exit points and directly connected transmission customers; and
- a dynamic allocation process where parties have no ability to adjust their demand in response to price and where the nature of demand is such that it

would not be appropriate to ration demand unless there was a significant curtailment event – the only points in the DTS that satisfy this criterion are distribution exit points with retailers at these points having little or no control over the use of gas by residential and small commercial customers.

Further detail on the auction and dynamic allocation process is provided below. This section also discusses the proposed transitional arrangements for AMDQ and AMDQ cc, because these rights would have some bearing on how capacity is allocated in the period immediately following implementation.

Auction

At entry points and non-distribution connected exit points, market participants would be required to purchase their capacity requirements through an auction.

There are a number of different ways that the auction could be designed, with the choice between them depending on, amongst other things, the nature of the products to be auctioned, the nature of demand, the number of bidders and the objectives of the auction. Having regard to these factors, the Commission' suggested outcomes are that:

- the auction of longer-term products take the form of:
  - an ascending clock uniform price auction, if it is feasible to do so – under this type of auction the 'clock price' ticks up by pre-defined amounts over multiple rounds until demand is less than or equal to supply; or
  - a sealed bid uniform price auction if the ascending clock auction is not feasible – under this type of auction all bidders submit a sealed bid at the same time and winning bidders pay the price of the lowest successful bid.
- the auction of shorter-term products take the form of a single round sealed bid uniform price auction; and
- a fixed proportion of the baseline capacity be reserved for shorter-term auctions (e.g. monthly, month ahead, day ahead or within day products) to allow new entrants access to capacity and minimise the risk of market foreclosure by incumbents.

From an economic regulation perspective, the Commission would also recommend that the AER be accorded responsibility for:

- approving the reserve prices to be used in the auctions[100]; and
- determining how any over or under recovery of revenue or prices be treated.[101]

100 The reserve price is essentially the reference tariff, being calculated on locational basis (similar to today), albeit for capacity rather than volumetric.

101 While the DTS service provider may (if a price cap rather than revenue cap was in use) retain any additional revenue as a result of outturn demand for capacity rights differing from forecast

The table below provides an illustration of how the various capacity products could be sold.

Table 6.1 Types of auctions

Capacity product	Auction design	Auction frequency
Quarterly	ascending clock, uniform price	annual
Monthly	ascending clock, uniform price	monthly
Day-ahead	single round sealed bid, uniform price	daily
Within-day	single round sealed bid, uniform price	hourly

The auction design related recommendations are only suggestions at this stage because before a final decision is made to implement a particular design, market participants would need to be consulted and the feasibility of particular auction designs would need to be assessed. The Commission therefore recommends that the GMRG be accorded responsibility for taking this forward.

Dynamic allocation of capacity

In contrast to the other entry and exit points in the DTS, market participants at distribution exit points would not be required to pre-purchase exit capacity. This capacity would instead be allocated on a dynamic basis by AEMO to market participants based on the volume of gas their customers consumed. This approach is akin to how AMDQ for Tariff V customers is currently allocated in the DTS. Barring any significant force majeure events, there would be no need to ration transmission capacity of distribution connected customers. This is appropriate given the nature of demand at these points.

From a retail competition perspective, the use of this type of allocation mechanism would enable all retailers (new entrants and incumbents) to access the distribution exit points. It also means that new entrant retailers would not have to commit to purchasing exit capacity when demand is uncertain and would prevent more established retailers from hoarding capacity at the distribution exit points.

In a similar manner to the current arrangements, the AER would be responsible for approving the reference tariffs for these products.

demand, any over-recovery resulting from auctions clearing above the reference tariff would be returned to market participants. This could either be directly through lower future reference tariffs or by the revenue being used to offset AEMO's congestion management fees.

AMDQ and AMDQ cc transition

The movement to the Southern Hub trading model and the entry-exit capacity regime would alter (or remove) most of the risks that AMDQ and AMDQ cc currently allow market participants to manage. In many ways, these instruments would be replaced by entry and exit rights, which would offer superior access to transmission capacity.

It would not be necessary or even feasible to retain AMDQ and AMDQ cc alongside entry and exit rights. This consequently raises the issue of the treatment of AMDQ and AMDQ cc rights previously allocated to market participants for periods following the commencement of the new arrangements. The Commission's recommendations are as follows:

- **Tariff V AMDQ**, which is dynamically allocated to retailers based on customer numbers, would essentially be replaced by the dynamic allocation of capacity at distribution exit points. **Tariff D AMDQ** at distribution exit points would also be replaced by the dynamic allocation process.

- **Tariff D AMDQ** holders at points other than the distribution exit points would, as a transitional measure only, be given the option to acquire firm capacity rights up to their current AMDQ holding for as far into the future as capacity is made available. This capacity would be directly allocated to AMDQ holders at the reference tariff, which means that they would not have to compete at the auction for capacity.[102] For Tariff D AMDQ holders that are supplied by a retailer, the new arrangements would allow the firm rights to be assigned to the retailer for the duration of their retail contract. At such time as the option was allowed to lapse, however, the holder would have no further priority rights.

- As to **AMDQ cc**, the Commission understands that the need to transition rights is likely to be less of an issue because these are time limited products. To the extent there are any AMDQ cc on foot when the transition occurs, the Commission would suggest employing a similar approach to that proposed for Tariff D AMDQ holders, with the exception being that AMDQ cc holders would only be able to acquire the right for the remaining term of their AMDQ cc.

6.4.2 Above baseline capacity

In order to promote the efficient utilisation of the DTS, the entry-exit system would include a mechanism to allow for the release of additional, shorter term capacity above the baseline level.

The Commission recommends that AEMO be accorded responsibility for the release of this capacity and that it be released through a day-ahead and/or within-day auction on an interruptible basis. Importantly, this capacity would only be available at entry and

102 It is worth noting in this context that AMDQ and AMDQ cc holders currently pay the reference tariff to access transportation capacity on the DTS.

exit points where all the baseline capacity has been sold, so it does not undermine the DTS service provider's ability to recover revenue from the sale of baseline capacity.

In the event the sale of above baseline capacity leads to constraints on the day (that is, more capacity being nominated for use by market participants than can be delivered), the interruptible nature of the entry and exit rights would provide AEMO with the ability to curtail those rights in order to manage the congestion.

6.4.3 Measures to encourage the release of secondary capacity

With the allocation of baseline capacity occurring well in advance of the gas day, there is a risk that market participants might not trade unused or unwanted capacity to others who might be able to use it and value it more, which would affect the efficiency with which the DTS is used. This may happen simply because there are insufficient incentives available to the holder to make the capacity available, although there could be a risk of deliberate hoarding.

The Commission therefore recommends two measures to encourage the release of secondary capacity:

- a short-term use-it-or-lose-it (UIOLI) mechanism for contracted but un-nominated baseline capacity at points with contractual congestion, which would be released to the market through a day-ahead auction after a specified nomination cut-off time; and
- the development of an electronic exchange that would enable market participants to trade secondary capacity on an anonymous basis.

These recommendations are consistent with the ones made in the East Coast Review stage 2 final report.[103] The table below provides an overview of the main characteristics and benefits of each recommended measure.

Table 6.2 Measures to encourage the release of secondary capacity

Measure	Recommendation	Key benefits
Auction for contracted but un-nominated capacity	• A daily, day-ahead auction for contracted but un-nominated capacity at points with contractual congestion; • Auction to occur shortly after the nomination cut-off time; • Reserve price to be set at zero.	• Provides an opportunity for market participants to access contracted but un-nominated capacity on a competitively priced basis; • Access is provided on a non-discriminatory basis, due to the transparency inherent in the auction process.

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

Measure	Recommendation	Key benefits
Secondary capacity trading	• Creation of an electronic exchange that would enable market participants to trade secondary capacity on an anonymous basis; • Trades carried out through the capacity trading platform should be given effect through an operational transfer; and • Publication of information on all secondary trades, including the price of the trade plus any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties.	• Trades are anonymous, not disclosing participant's position; • Reduced search and transaction costs for market participants; • Gives existing market participants the opportunity to recover costs for contracted but unwanted or unutilised capacity; and • Provides new and smaller organisations with the chance to purchase firm capacity on a fully contracted entry or exit point for sets periods of time.

6.5 Investment in new baseline capacity

Under the proposed entry-exit system there would be times when the demand for existing baseline capacity would exceed supply and need to be allocated between parties in the manner in section 6.4.1. There would also be times when it would be efficient to expand the baseline capacity to meet future demand. A process is therefore required to determine when it is efficient to ration demand versus when it is efficient to expand the baseline capacity.

The Commission recommends that a market-based mechanism be used to signal the need for investment in new baseline capacity in the DTS, where it is feasible to do so, in order to promote timely and efficient investments in the network.

In relation to entry points and exit points other than distribution networks, the Commission's preferred outcome is for capacity expansions to be signalled through a hybrid open season-integrated auction, which would be conducted at least every two years. Box 6.2 provides a brief overview of the hybrid open season-integrated auction. Further detail on this auction can be found in the Technical Report.

Box 6.2 Hybrid open season-integrated auction

The hybrid open-season integrated auction is a non-discriminatory market based mechanism that can be used to signal the need for incremental capacity and also allocate existing and incremental capacity if it is established that investment is required. The use of this mechanism has recently been recommended in Europe as best practice for future investment in incremental interconnection capacity.[104]

104 ACER, *ACER Recommendation on the amendment to the Network Code on Capacity Allocation Mechanisms in gas transmission systems*, October 2015. The European Commission is yet to endorse this recommendation, but if it is approved it would take effect in July 2017.

Under this mechanism, a non-binding open season would be carried out at *least* every two years to determine if there is sufficient interest amongst market participants to expand the capacity of the DTS. If there is sufficient interest, then the DTS service provider would be required to:

- investigate the options for expanding capacity (the design phase); and
- submit a proposal to the AER setting out the details of the expansion options and proposed price steps for the capacity to be subject to an integrated auction.

If, on the other hand, there is insufficient interest then the integrated auction would not be carried out and existing capacity would be sold through the standard auction process.

The term 'integrated auction' is used in this context to refer to an auction that can be used to signal the need for incremental capacity and allocate both existing and incremental capacity. To carry out an integrated auction, a schedule of increasing price steps must be developed for varying levels of capacity expansions against which parties can indicate their willingness to pay for capacity.

Once the price steps are established the integrated auction can be conducted. If this results in:

- demand being less than or equal to existing baseline capacity, then the existing capacity would be allocated to the bidding parties at the existing reference tariff; or
- demand exceeding the existing baseline capacity, then if the capital expenditure criteria in the NGR are expected to be:[105]
  - satisfied and the DTS service provider decides to expand capacity, the existing and incremental capacity (when it becomes available) would be allocated to bidding parties at the price step associated with the capacity expansion; or
  - not satisfied, existing capacity would be allocated at the price where demand is less than or equal to the existing baseline capacity (i.e. capacity would be sold at a premium to the current reference tariff).

The only points in the DTS where it would not be feasible to employ this type of mechanism are the distribution connected exit points where capacity would be dynamically allocated to market participants based on the volume of gas consumed by their end-customers. The nature of demand at these points is such that it is unlikely to be possible to get long-term commitment, and therefore any useful investment signals, from retailers. An alternative approach is therefore required at these points in the DTS.

105 See rule 79 of the NGR.

The Commission recommends that capacity expansions at distributed connected exit points continue to be signalled through the same planning process that is currently employed, with any investment proposal approved by the AER as part of the Access Arrangement review process.

6.6 Implications for the economic regulatory framework

To implement the entry-exit system, a number of changes would need to be made to the DWGM related provisions in the NGR and, potentially, the NGL. Some refinements would also need to be made to the economic regulatory framework that currently applies to the DTS, which would require further changes to the NGR and the discharge of the AER's economic regulatory functions.

While some changes to the regulatory framework are required, the rationale for regulating the DTS and the overarching objectives of regulation, as defined in the National Gas Objective (NGO), would be unchanged by the move. The level of regulatory oversight would also be unchanged, with the AER retaining responsibility for approving the DTS service provider's revenue requirement and reference tariffs and reserve prices for entry and exit capacity.

The movement to the entry-exit system would nevertheless necessitate some changes to the economic regulatory framework to give effect to the recommendations that:

- the AER be accorded responsibility for approving the baseline capacity and developing schemes to provide incentives to the pipeline owner to make this capacity available;
- baseline capacity be released to the market in the manner described in section 6.4.1;
- an auction of contracted but un-nominated capacity be carried out at contractually congested points of the DTS; and
- a market-based mechanism, such as the hybrid open season-integrated auction, be used to signal the need for further investment in the DTS and to allocate the expanded capacity.

Further detail on the types of changes that would be required is provided in the Technical Report.

7 Transition to the Southern Hub design

Box 7.1 Recommendations

There is a risk that upon introducing the Southern Hub, liquidity in the exchange may initially be low, diminishing many of the key benefits of the reform.

There may also be some one-off adjustments that market participants will need to make as the Southern Hub is introduced.

Recommendation 4: Market trials should be undertaken to determine the requirement for, and design of, transitional measures that may be appropriate to help stimulate liquidity in the commodity market and mitigate the impacts of changed market arrangements for market participants.

Without prejudging the outcome of the trial process described above, the Commission considers the following transitional measures would provide the most benefits on commencement of the Southern Hub model:

- financial tolerances, which would provide market participants with financial protection against residual balancing action costs, for imbalances up to a threshold. Instead these costs would be socialised across all market participants; and
- financial incentives for a market participant to be in balance on a daily basis, in order to concentrate liquidity into simple daily or balance-of-day products which market participants would require to remain in balance.

These transitional measures are expected to stimulate liquidity and provide protection to market participants in adjusting to the new regime. They should also provide a pathway to the implementation of the target model, because:

- they are relatively simple to implement;
- all of the main features of the target model would be implemented from day one, albeit with supporting measures to ensure the market functions adequately from the outset; and
- they can be readily rolled back over time.

Furthermore, the Commission considers that these transitional measures should avoid substantially diminishing the benefits of the target model during the transitional period.

If the above transitional measures are insufficient to generate liquidity, the Commission recommends that other transitional measures (in particular a market maker scheme) should be considered for subsequent implementation.

7.1 Introduction and context

An advantage of the Southern Hub is that it would provide market participants with greater flexibility in the way they manage their gas requirements. Participants would be able to minimise their exposure to residual balancing charges by any combination of voluntarily trading gas (which can be done on a continuous basis) and adjusting their physical injections or withdrawals.

For participants to have a genuine choice as to how they manage their positions, it is important that gas trading is an attractive option. However, there is a risk that upon introducing the Southern Hub, many market participants – lacking experience with and confidence in hub trading – may initially choose to manage their imbalances entirely by adjusting their injections and withdrawals. This may precipitate a spiral of low liquidity within the hub, as participants collectively lose confidence in the market and seek to retain their flexible gas for their own potential use, instead of risking having to acquire flexible gas on the market. This outcome would diminish many of the key benefits of the reform, and might also mean that gas is not allocated to its highest-valued use.

There may also be some one-off adjustments that market participants will need to make as the Southern Hub is introduced. The existing market provides incentives for participants to inject more gas than they expect to withdraw, to effectively ‘self-insure’ against the risk and cost of being short. The overall excess of injections has enabled a number of small market participants to source relatively inexpensive gas on the DWGM under certain conditions. The new arrangements may, by removing the current incentives for market participants to be long of gas, limit small market participants' ability to source cheap gas in the manner to which they have become accustomed.

In the Commission’s view, neither of these concerns represents enduring problems with its recommended reforms. However, a range of transitional measures should be used to stimulate liquidity at the hub and to limit the impact of the changed market design on particularly smaller participants. Over time, once liquidity has been established and market participants have adjusted, the transitional measures would be removed.

This chapter:

- explains the rationale for transitional measures;
- briefly assesses various transitional measures which could be implemented;
- explains that market trials to be conducted by the GMRG may be particularly valuable in determining the appropriateness of various transitional measures; and
- makes recommendations for transitional measures, subject to the outcome of market trials.

7.2 Rationale for transitional measures

As noted above, the Commission and stakeholders have identified two potential concerns that may warrant transitional measures in the design of the commodity and balancing arrangements. This section explains these two concerns in greater detail.

7.2.1 Potential illiquidity in the Southern Hub

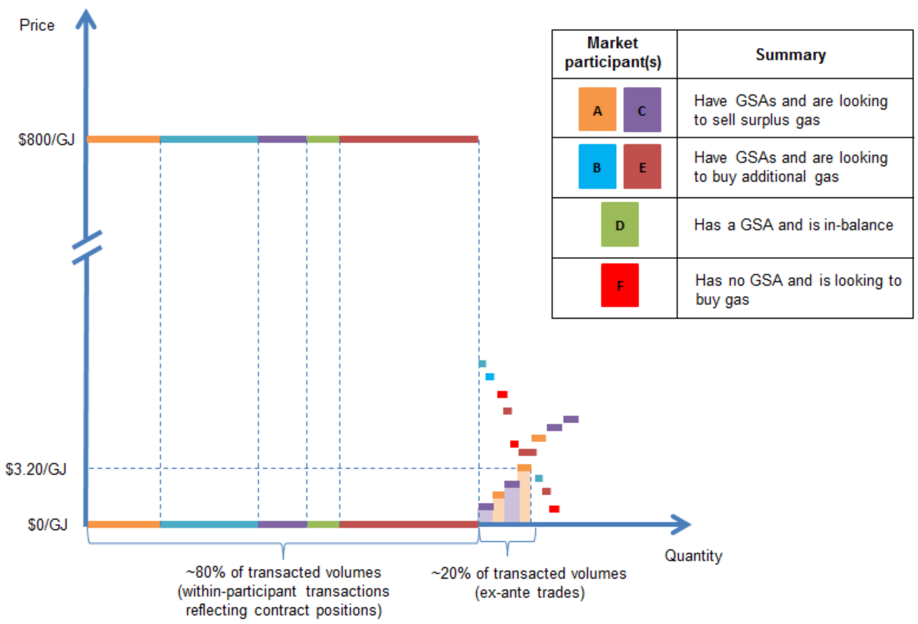
In moving from a mandatory to a voluntary market, there is a risk that participants may – lacking experience with and confidence in hub trading – make an initial decision not to trade on the hub. Instead, participants may choose to self-insure against the risks and costs of being short by holding gas they do not immediately require in reserve. This could lead to a worsening spiral of illiquidity in the Southern Hub that would not necessarily resolve of its own accord.

The risk of such an outcome can be illustrated by focussing on how participants respond to incentives under the current DWGM design.

In order to manage their exposure to the market price in the current DWGM, market participants typically offer gas sufficient (or nearly sufficient) to meet their own requirements at the market floor price ($0/GJ). This gas is then "traded" by being matched with bids made by the same market participant at the market price cap ($800/GJ). Approximately 80 per cent of gas is "transacted" in this way.

As discussed in section 2.3.1, in the current DWGM, market participants are required to offer all of their gas into the market at each schedule. As such, they typically offer any additional gas not required to meet their own requirements at prices above the market floor, with the aim of selling the gas to another market participant. A stylised example of this behaviour is given in Figure 7.1.

Figure 7.1 Stylised offer and bid behaviour in DWGM



Conversely, as a voluntary market, the new Southern Hub model would not oblige market participants to offer all (or any) of their gas into the market. At market start, participants may continue to rely on their own long term contract positions to meet their own gas demand. In time, as confidence and liquidity in the market grows, market participants may source more and more of their gas from one another through the exchange, increasing liquidity and precipitating many of the expected benefits of the reforms.

However, because market participants would no longer be required to offer gas additional to their own demand into the market, there is a concern that at market start market participants may elect against doing so, or only do so at a very high price. To the extent they adopted this approach, market participants would forgo the benefits of selling gas, but would be able to retain flexibility to meet potential changes in their own demand.

Illiquidity may develop as a result of the risk that a significant and growing number of market participants could respond in this manner. Under such a scenario, instead of market participants sourcing more and more trades from the virtual hub, fewer and fewer trades could occur, stymying liquidity. Doubts over hub liquidity could incentivise market participants to hold onto more of their own gas in reserve, rather than releasing it to the market, because of the risk of being short of gas and needing to source it from the now illiquid hub. This could result in a self-reinforcing cycle of greater illiquidity.

This behaviour may be exacerbated by the existing risk management cultures and procedures of market participants, which, if not reflective of the actual risk appetite of market participants, may result in efficient trades not occurring. These cultures and procedures may take some time to change, by which point confidence in the market may have been damaged and difficult to restore.

Were illiquidity to emerge, this would have a number of negative consequences:

- In general, it would forestall many of expected benefits of the reforms. As discussed in Chapter 3, liquidity in the exchange is required in order for market participants to more effectively manage risk through physical products, for the potential emergence of financial derivatives to further manage risk, and for transparent and meaningful reference prices to develop.

- It would expose a number of small market participants that source much or all of their gas through the existing DWGM and have limited or no physical positions to potentially high market prices. In the extreme, this may cause these market participants to exit the market, and impose a barrier for further entry into the market by new market participants.

The Commission notes that regardless of the level of liquidity, however, *system security* would not be threatened – at some price, counterparties will trade with AEMO to alleviate any system security issue. Furthermore, AEMO would retain its existing powers to direct market participants in extreme circumstances to address the most serious or imminent system security issues.

7.2.2 Changed balancing incentives

The introduction of the Southern Hub may also impact some small participants who have to date benefitted from a specific design feature of the DWGM, which allows them to purchase relatively inexpensive gas under certain conditions, as explained in this section. In moving to the Southern Hub, this benefit to some small market participants may be removed. The Commission considers it may be appropriate, on a transitional basis, to mitigate the withdrawal of this benefit from these market participants.

As explained in Chapter 2, market participants are presently required to forecast their uncontrollable gas usage for the gas day, which is automatically "bid" into the auction at the market price cap and automatically scheduled. If market participants incorrectly forecast, they are exposed to deviation payments, paid at the market price of the next schedule on the quantity of gas that reflects the deviation between their scheduled and actual injections and withdrawals.

The risk associated with incorrect forecasting is asymmetrical. If a market participant over-forecasts (i.e. is long), it is likely to receive a lower price for its gas than it might otherwise have been paid, but not substantially lower – prices in the DWGM are typically less than $10/GJ, and cannot be lower than $0/GJ. This means that market participants typically face a maximum opportunity cost of over-forecasting of no more than $10/GJ.

On the other hand, if a market participant under-forecasts (i.e. is short), it is likely to pay a higher price for the gas than it might otherwise have paid, with the potential for this price to be substantially higher – up to $800/GJ, which is the market price cap. This may create an incentive for market participants to 'self-insure' against demand uncertainty by deliberately providing AEMO with forecasts for uncontrollable demand that are greater than their actual expectations.[106]

This is explained through the worked example in Box 7.2.

Box 7.2 Asymmetric risk of deviation payments

In the current DWGM, if a market participant forecasts too much demand (the amount of gas actually withdrawn is less than forecast and scheduled), the market participant will receive a (positive) deviation payment, equal to the quantity of deviation between actual and schedule, multiplied by the market price in the next schedule.

Take for example a market participant which is scheduled to withdraw 100GJ but actually withdraws 90GJ. The market price in the upcoming schedule is $4/GJ. The market participant will receive a deviation payment of $40 for being long of gas ((100GJ-90GJ) x 4$/GJ). In effect, the market participant has sold 10GJ of gas that was additional to its needs at $4/GJ.

Other things being equal, if the market participant was long of gas, the market

106 In the year 1 September 2015 to 31 August 2016, 73 per cent of scheduling intervals had system wide actual withdrawals less than system wide forecast withdrawals. Source: AEMC analysis.

price in the upcoming schedule is likely to be lower than the current schedule. This is because if the participant was long, the system overall is more likely to be starting from a long position. Hence demand for additional gas in the upcoming schedule is likely to be lower than if the system had initially been balanced or short of gas. Had the market participant accurately forecast its withdrawals (and been scheduled as such), then it likely would have been paid a higher price for the sale of gas additional to its needs - say $5/GJ in our example, at a profit of $50. By forecasting long, the market participant has incurred an opportunity cost of $10.

Now, consider an example where the market participant is short of gas, such that it is scheduled to withdraw 100GJ but actually withdraws 110GJ. In this case, the market price in the next schedule is likely to be higher than the previous schedule – say $6/GJ. The market participant will incur a deviation payment of $60 for being short of gas ((100GJ-110GJ) x 6$/GJ)). In effect, the market participant has bought 10GJ of gas at $6/GJ. Again, had the market participant accurately forecast its withdrawals, it would only have paid $5/GJ for the same gas. By forecasting short, the market participant has incurred an additional cost of $10.

If market participants could perfectly predict their actual demand, they would maximise their revenues (or minimise their costs) by submitting those forecasts – assuming that market prices decrease between schedules when a market participant is long and increase when a market participant is short. However, as market participants lack perfect foresight of their own actual demand, they cannot avoid exposure to deviation payments.

The issue market participants face is that their exposure to deviation payments is not symmetric:

- The potential opportunity cost of being long is capped per GJ at the difference between the market price and the market floor price (i.e. $0/GJ). In the example above, if prices decline dramatically between schedules, a long market participant will only be exposed to a maximum opportunity cost of $5/GJ.
- On the other hand, the potential cost of being short is capped per GJ at the absolute difference between the market price and the market price cap (i.e. $800/GJ). The maximum cost is in this example $795/GJ.

In response to this asymmetric risk, market participants may have incentives to deliberately provide AEMO forecasts of their uncontrollable demand that are higher than their "actual" forecasts (i.e. based on their true estimate of demand). The fact that all market participants face the same asymmetric risks and incentives to ‘over-forecast’ may explain why market prices typically decline over the course of the day.[107]

107 In the year 1 September 2015 to 31 August 2016, the average 6am price was $5.92 and the average 10pm price was $5.01. The 6am price was higher than the 10pm price 74 per cent of the time. Source: AEMC analysis

The Commission understands that as a consequence of many market participants deliberately providing AEMO with forecasts for uncontrollable demand that are greater than their actual expectations, a number of small market participants have taken a different approach. Rather than managing price risk in the DWGM through a GSA and being deliberately long compared to their actual forecasts, they offer very little or no gas into the market and only bid out of the market. In effect, these participants are largely or fully exposed to the DWGM price.

The Commission understands that some market participants undertaking this strategy have attempted to enter into GSAs to manage their risk exposure, but have been unable to do so at a price they consider reasonable in comparison to typical DWGM prices. This may be because they are so small that they have a weak negotiating position with producers offering GSAs. It may also be because such an approach avoids the cost involved in hedging the DWGM price, particularly in an environment where smaller participants consider that their demands are too small to materially affect the DWGM price.

Substantial unhedged exposure to the DWGM price by some market participants may be considered to be undesirable. Poorly hedged market participants risk substantial losses were DWGM prices to become more volatile. However, the Commission understands that such participants make up an extremely small proportion of the gas market, meaning they are unlikely to cause cascading financial failures were they to become insolvent as a result of a high DWGM price event(s).

On the other hand, the current arrangements may actively encourage small retailers to participate in the market by enabling them to purchase lower priced gas compared to what they would otherwise. This may provide competitive tension to the larger market participants, to the ultimate benefits of consumers.

In the Southern Hub, the incentive for market participants to inject more gas into the system than they withdraw may not exist to the same degree. Through the continuous balancing mechanism, market participants may be able to manage unexpected changes in their demand on a more continuous basis, and with greater flexibility, either through buying on the exchange or by adjusting their own injections and controllable withdrawals in a timely manner.

That said, there may continue to be an incentive for market participants to go long in the new market. This is because the opportunity cost associated with the system operator selling a market participant's gas if the market participant is long (and the system is too long) may be less than the cost of the system operator buying gas on behalf of a market participant if the market participant is short (and the system is too short). That is, the asymmetric risk between being long and short may remain to a greater or lesser extent in the Southern Hub model.

7.3 Possible transitional measures

In light of these concerns, the Commission considers that transitional measures may be required for a limited period of time after the introduction of the Southern Hub, in order to:

- help stimulate liquidity in the commodity market; and
- mitigate against the impacts of changed market arrangements for market participants.

It is important to recognise that transitional measures inevitably have disadvantages. Indeed, were this not the case, they would be included as a design feature of the "target model". Consequently, the transitional measures should also:

- avoid substantially diminishing the benefits that are envisaged to arise from the introduction of the Southern Hub, while they are in place; and
- allow for the subsequent transition to the target model in a timely manner, so that the full benefits can be realised.

The Commission engaged Cambridge Economics Policy Associates (CEPA) to devise and assess transitional measures against these criteria. Its analysis can be found on the AEMC's website.[108] It drew upon international experience, particularly transitional arrangements for similar European regimes, as found in the European Union’s (EU’s) Balancing Network Code.[109]

A brief description of each transitional measure considered, and its pros and cons, is given below. More detail on each potential transitional measure considered can be found in CEPA's report. Broadly, these measures can be categorised as either:

- market design transition measures, associated with ensuring that sufficient volumes of gas will be traded at the new Southern Hub and that a robust set of reference prices will be available for balancing purposes, both for market participants and AEMO in conducting its residual balancing role; and
- financial relief measures for market participants, which would protect them against the full commercial disciplines of market based balancing.

One or a combination of measures could be used to address the potential transitional issues.

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108 CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*. Available at www.aemc.gov.au

109 European Union, *Network Code on Gas Balancing of Transmission Networks*, Chapters X and XI. Available at: http://www.entsog.eu/public/uploads/files/publications/Balancing/2013/BAL%20NC%20-%20Commission%20Regulation.pdf

7.3.1 Market design transitional measures

Non-continuous balancing

As noted in Chapter 5, the Commission's preference is for a continuous balancing regime in the target model. This approach is preferred because AEMO would not be required to undertake unnecessary residual balancing action (for example, at the end of the day), the cost of which would be passed to market participants who are out of balance. Furthermore, market participants would not be arbitrarily incentivised to return to being in balance to avoid residual balancing costs.

However, daily balancing does have the advantage of concentrating liquidity into simple daily or balance-of-day products which market participants would require to remain in balance. Transitionally, daily balancing could be implemented in addition to continuous within-day balancing, to provide adequate signals to market participants for balancing within the day and to concentrate liquidity into daily products.[110]

As an alternative to a daily balancing regime, market participants might be charged an end-of-day linepack fee. Under this approach, the system operator would not take any actions at the end of the day to return the system to being in balance (and so no costs would be incurred in doing so), but instead a fixed fee (for example on a per GJ basis) would be charged to out of balance market participants. A market participant's individual linepack position would not be changed as a result of paying the linepack fee (unlike the case of daily balancing, where gas traded through the exchange would be credited or debited against out of balance market participants).

The linepack fee approach would provide an incentive to the market participant to purchase daily or balance-of-day products, and hence concentrate liquidity, without the system operator incurring costs. Revenue generated by the system operator from the end-of-day linepack fee could be used to offset residual balancing action costs, or returned to market participants in a socialised manner.

Physical self-supply restrictions or unbalanced obligations

Physical self-supply restrictions would be a partial restriction on the amount of physical consumption that any market participant could supply from within its own portfolio.[111] The objective would be to force market participants to trade and manage at least some of their balancing risks outside of their portfolio.

Alternatively, some market participants could be required to have net long nominated positions (i.e. inject more than they withdraw) and others net short nominated

110 For a more detailed discussion, see: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 25-27. As a permanent design feature, the Belgian market has a continuous within day balancing regime plus an end of day balancing regime.

111 For a more detailed discussion, see: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 28-30.

positions (withdraw more than they inject).[112] Market participants would then be required to balance by trading on the day with each other.

Aside from their inherent intrusiveness, these options are likely to be difficult to implement, monitor and enforce. Furthermore, there are serious practical complications, for example:

- whether to force some shippers to nominate long and others short, and if so, on what basis; and
- whether the obligations on market participants should vary day to day, and if so, on what basis.

System operator primary balancing responsibility

A transitional scheme whereby the system operator has primary balancing responsibility allows an immediate move towards day (and further) ahead trading through the Southern Hub exchange. This would involve having a gate closure point before the gas day, beyond which the system operator would take primary responsibility for balancing, rather than the residual balancing role in the target model.[113]

Under the simplest approach, market participants would be required to nominate injections and withdrawals at the time of gate closure such that they were projected to be in balance, taking into account any net trades entered into before gate closure. For example, if a market participant had sold 20TJ (net) of gas for delivery on the day and had a forecast demand of 30TJ, it would be required to nominate to inject 50TJ.

After gate closure, the system operator would take over all balancing responsibilities and would meet any within-day variations from the aggregate of market participants' physical nominated flows to physically balance the system. This would be achieved through a continuous balancing platform or scheduled auctions (potentially at the same time as the current DWGM schedules) where the system operator would purchase or sell gas from market participants.

During the gas day, market participants would be incentivised to meet their nominations made at gate closure, subject to any adjustments for exchanging gas with the system operator.

The underlying rationale for the system operator taking primary balancing responsibility as a transitional measure is that market participants make their best view of supply and demand before gate closure and are incentivised to "stick with the program" after the gate shuts, while the system operator takes over responsibility for dealing with variations afterwards. This would provide confidence to the system

112 This is described by CEPA as "unbalanced obligations". See: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 28-30.

113 For a more detailed discussion, see: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 28-30, 45-51.

operator that it would be able to maintain system security regardless of the action (or inaction) of market participants).

Where a market participant deviates from its nominations, this might result in costs for the system operator to maintain system security. These costs would be targeted against those market participants who deviate.

More complex approaches would allow market participants to:

- trade with one another (rather than just with the system operator) after gate closure;
- plan on a deficit or surplus in advance, and so nominate unbalanced positions at gate closure, and then have the system operator source their gas during the day (for a cost);
- allow renominations after gate closure to match any unexpected changes in demand or supply.

Potentially, this approach could be wound back over time by progressively making the gate closure time later. Over the period that the transitional measure was in effect, market participants would assume an increasingly large role for primary balancing responsibility.

This approach has a number of parallels to the existing DWGM, in that primary balancing responsibility would be retained by the system operator, buying or selling gas through a scheduled approach (like the DWGM) or through an exchange. Indeed, the existing requirement for market participants to bid and offer all gas could be retained (i.e. market participants could be required to offer and bid all gas which they did not nominate at gate closure). Alternatively, market participants could voluntarily trade gas with the system operator.

A potential downside to this approach is that because market participants would not have responsibility to manage their position on the day by trading gas through the exchange, market participants' familiarity with the exchange may be diminished. This may disrupt the development of liquidity at the exchange for products that are day (and further) ahead. Consequently, while concerns surrounding on the day balancing liquidity may be addressed by the system operator having primary balancing responsibility, greater than day ahead liquidity may be reduced.

Another downside to this approach is that it is likely to involve significant market design work solely for a transitional process. This is likely to be the case for even the most simple design, or where many of the features of the existing DWGM balancing regime are retained. Furthermore, upon implementation it would require market participants to learn a new process which would then be phased out and replaced by the target model, adding cost and complexity.

Market maker obligations

Market making could involve a commitment for certain market participants to continually (or during specific trading windows) show bid and offer prices for a minimum volume of gas for particular products at a maximum bid-offer spread.[114] This might be implemented as a requirement on certain market participants, or alternatively, AEMO could competitively tender for market participants to fulfil this role, for a fee (which would then be recovered from all market participants).

The market maker role would guarantee that gas was available for trade. The maximum bid-offer spread should mean that prices were reasonably reflective of underlying supply and demand conditions – as a market maker which had decided to withhold its gas for its own balancing requirements would not be able to simply price its flexible gas very highly without risking having to buy gas at a similar price.

As noted above, liquidity tends to be self-reinforcing. Even the limited liquidity that a market maker would provide to the market might encourage other parties to participate and compete to be the best buyer or seller, stimulating further liquidity. The posted prices by the market maker may also help to improve the transparency and quality of prices at the Southern Hub.

However, as with the physical self-supply restrictions or unbalanced obligations, market maker obligations would be intrusive, requiring market participants to sell their gas or buy another market participant's gas when they would otherwise not want to do so. Furthermore, if financial incentives were offered to market participants to perform the market maker role, these costs would have to be recovered from other market participants.

System operator flexible gas

In its residual balancing role, AEMO could procure its own long-term GSAs with producers on an ex-ante basis, and use this gas to balance the system, rather than gas procured on the exchange.[115]

If the exchange is illiquid, the option of independently procuring gas may serve to reduce balancing costs to the system operator, and, in turn, to market participants.

However, there are a number of potential negative features of this approach:

- The approach may entrench illiquidity, because the system operator is not purchasing gas on the exchange.

114 For a more detailed discussion, see: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 28-30, 41-42.

115 CEPA additionally suggests that as a transitional measure, 'system operator friendly' products (such as locational products) could be created and sold on the exchange. The Commission considers that this may be important in the target model to manage system security issues arising from matters other than system wide balancing. See section 5.4.

- Charging residual balancing action costs to the market participant which caused the residual balancing action would be difficult, because it would be difficult to determine the proportion of the ex ante cost of the GSA to be charged to each market participant on each occasion that residual balancing action is taken.

- AEMO would be required to enter into contracts, the costs of which will ultimately be recovered from market participants, on a non-transparent basis.

7.3.2 Financial relief transitional measures

Tolerances

The application of tolerances to balancing would provide market participants with some financial protection against certain residual balancing action costs.[116] Market participants would be provided a quantity of gas which they could be out of balance before residual balancing action costs would be attributed (targeted) to them. Any non-targeted residual balancing costs would be socialised, for example in proportion to the volume of gas supplied or demanded (or both) to or from the system.[117]

There are a number of ways in which tolerances could be applied. For example, a market participant might have a 20GJ tolerance. If the market participant is 10GJ out of balance when residual balancing action is taken, all of the costs that would otherwise have been targeted to the market participant would be socialised. Should the market participant be 50GJ out of balance when residual balancing action is taken, costs associated with 20GJ would be socialised, with the remaining 30GJ above the tolerance targeted to the market participant. Socialised costs might be recovered from market participants on the basis of their gas throughput on the day, for example.

Design considerations for tolerances include:

- whether tolerances are applied to a quantity of gas or a dollar amount of costs arising from residual balancing actions;

- the quantity of the tolerance;

- the level of protection afforded within the tolerance amount (e.g. financial protection might be afforded to a proportion of costs arising within the tolerance);

- whether tolerances are provided as an absolute quantity regardless of market participant, or whether the tolerance should be a proportion of a market participant portfolio (based on throughput, for example). An absolute quantity of

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116 For a more detailed discussion, see: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 32-35.

117 In the event of cost socialisation, each market participants' POS would be credited with an amount of gas commensurate with the amount of socialised costs they paid.

protection would tend to favour smaller market participants (as the tolerance is likely to make up a larger proportion of their portfolio); and

- on what basis would socialised costs be recovered from market participants.

The application of financial tolerances or balancing cost socialisation meets both key objectives of transitional measures identified in section 7.2. Financial tolerances would:

- reduce a market participant's financial exposure to targeted residual balancing action costs during a transition period; and
- limit market participants' downside risk of having insufficient flexible gas to avoid being out of balance, while retaining market participants' incentive to sell flexible gas to the system operator, stimulating liquidity.

Financial protection could be steadily decreased over the transitional period, on a pre-determined path or the basis of pre-determined triggers, with market participants exposed to an increasing proportion of residual balancing costs over time. This would allow market participants to gradually adjust to their new responsibility of individually being in reasonable balance in the Southern Hub. A shadow regime could be run so that market participants could see what their financial exposure would have been were it not for their tolerances, providing more opportunity for market participants to become accustomed to the new balancing regime.[118]

However, a negative side-effect of introducing financial relief measures is cost socialisation. It exposes all market participants to the costs of residual balancing action, including those that did not contribute to creating the costs. It also weakens the incentives on market participants to be in balance, with the potential for more residual balancing action being taken, at greater overall cost.

7.4 Market trials

The discussion of the rationale for transitional measures in section 7.2 highlights that market participants' behaviour is likely to be a key determining factor for whether transitional measures are required. Further, the likely efficacy of the various transitional measures may also be dependent on market participants' behaviour.

Accordingly, the Commission recommends that the market trials described in section 3.4.2 be undertaken to determine the requirement for, and design of, transitional measures. These trials should help to reveal:

- whether market participants are likely to hold onto their gas not required for their own needs and not offer it to the market (or offer it at a very high price), resulting in a self-reinforcing spiral of illiquidity;

118 For a more detailed discussion of the shadow regime, see: CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 32-35.

- whether there are incentives in the Southern Hub to typically supply more gas into the hub than withdraw (i.e. be consistently long); and
- the likely response of market participants under various transitional arrangements.

7.5 Assessment of transitional measures

Without prejudging the outcome of the trial process described above, the Commission considers the following transitional measures would be likely to provide the most benefits on commencement of the Southern Hub model:

- financial tolerances; and
- a daily balancing regime in addition to continuous balancing.

These transitional measures are expected to stimulate liquidity and provide protection to market participants in adjusting to the new regime, for the reasons described above. They should also provide a pathway to the implementation of the target model, because:

- they are relatively simple to implement;
- all of the main features of the target model would be implemented from day one, albeit with supporting measures to ensure the market functions adequately from the outset; and
- they can be readily rolled back over time.

Furthermore, the Commission considers that these transitional measures should avoid substantially diminishing the benefits of the target model during the transitional period.

Other transitional measures, such as a market maker obligation, should be considered for subsequent implementation if the above transitional measures are insufficient. These findings are consistent with recommendations provided by CEPA.[119]

The Commission notes that compared to European markets which have introduced transitional measures to stimulate liquidity, the Victorian gas market starts at a position of relative strength with regard to its ability to adapt to the new market because of years of:

- reliable DWGM operation and sourcing of gas flexibility for balancing purposes;
- active retail market competition; and
- experienced market participants and system operator.[120]

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119 CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, pp. 52-55.

For this reason, and consistent with CEPA's assessment, the Commission expects that the transitional period might be relatively short (e.g. less than 18 months). A timetable, or triggers, for rolling back the transitional measures should be clearly specified to provide market participants with clarity around their upcoming responsibilities.

7.5.1 Financial tolerances

With regard to financial tolerances, the Commission considers that they should be applied on an absolute basis to all market participants. This should provide small market participants in particular (who may be most exposed under the new arrangements) transitional protection. In turn, this should allow them to continue to provide competitive tension to the market, to the ultimate benefit of consumers.

In implementing financial tolerances, it would be important that the measures are rolled back as quickly as possible (while ensuring that liquidity is not stifled and that market participants are sufficiently protected), so that the disadvantages of cost socialisation are removed in a timely manner.

7.5.2 Daily balancing regime

The Commission considers that a daily balancing regime in addition to a continuous balancing regime within the day may be appropriate.

As discussed above, a benefit of this approach is that it would concentrate liquidity into daily and balance-of-day products.

This approach may be particularly appropriate if financial tolerances are put in place for within-day balancing. Absent of end of day balancing, high financial tolerances may result in some participants being continually out of balance, with the costs of this being socialised to all market participants.

The GMRG should consider whether financial tolerances should also be applied to the daily balancing regime in addition to the within-day continuous balancing regime. If so, the GMRG should also consider whether the tolerances should be less than those applied to the within-day regime, in order to provide sufficiently strong incentives on market participants to regain a reasonably balanced position and hence concentrate liquidity into daily and balance of day products.

CEPA considered that a daily balancing regime in addition to a continuous within-day balancing regime may be important not only as a transitional measure but as an enduring feature of the target model.[121] The GMRG should consider the appropriateness of this design feature both transitionally and in the target model.

The GMRG should also consider the relative merits of a daily balancing regime and an end-of-day linepack fee to stimulate liquidity.

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120 CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, p. 52.

121 CEPA, *Transitional measures for reforms to the Victorian Declared Wholesale Gas Market*, p. 54.

7.5.3 Other transitional measures may be appropriate in the future

Should the transitional arrangements implemented upon commencement of the Southern Hub model be insufficient in promoting liquidity and mitigating against the negative impacts of changed market arrangements for market participants, further transitional measures could be considered for subsequent introduction.

Of the approaches considered, the Commission considers the market maker may be the most appropriate because it guarantees that gas will be available for trade. Furthermore, depending on the design of the maximum bid-offer spread, gas prices should be reasonably reflective of underlying supply and demand conditions.

However, the Commission considers that such approaches should not be taken immediately as they involve relatively intrusive regulatory interventions in the market that may in principle not be necessary if the other individual transition measures deliver their objectives.

A 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.[122]

122 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.

B Assessment framework

This appendix outlines the assessment framework that the Commission has used 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 Victorian Government's terms of reference for the DWGM review (provided at Appendix A) requested the AEMC to:

> "...consider whether the DWGM provides 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."

Specifically, the terms of reference requests that the AEMC consider the following four issues:

- **Effective risk management in the DWGM**: whether market participants are able to manage price and volume risk and options to improve the effectiveness of risk management activities.
- **Signals and incentives for efficient investment in and use of pipeline capacity**: whether investment in the DTS will occur in an efficient and timely manner and options to strengthen the signals and incentives for efficient investment.
- **Trading between the DWGM and interconnected pipelines**: whether the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines, and options to allow producers and shippers to effectively operate across gas trading hubs on the east coast without incurring substantial transaction costs.
- **Promoting competition in upstream and downstream markets**: whether the DWGM continues to encourage the introduction of new gas supplies to the market and promote competition among retailers for the sale of gas, and the extent to which the design of the DWGM may be a deterrent to large users participating in the market.

In assessing these four issues, the Commission has applied the assessment framework set out below.

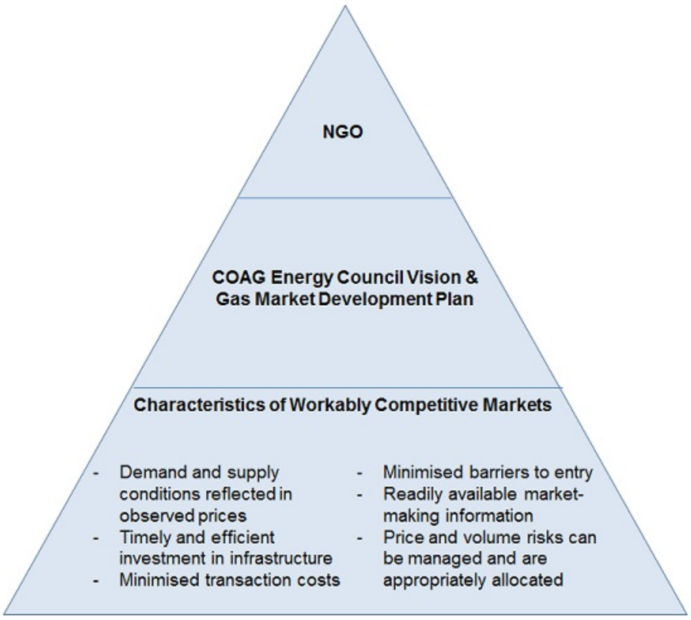
B.1 Assessment framework structure

In accordance with the terms of reference for the two reviews, 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 has had regard to the Energy Council's Vision and Gas Market Development Plan. The Vision is a statement agreed by the Commonwealth, state and territory energy ministers setting out the high level direction that gas market development should take in Australia for the NGO to be achieved. The Gas Market Development Plan is a program of work currently underway that supports the Vision.

Sitting below the NGO and Vision are high level attributes that the Commission considers support the development of well-functioning, workably competitive markets and that are generally required for the NGO and Vision to be achieved. The relationship between the three aspects of the assessment framework is illustrated in Figure B.1, and each is discussed below.

Figure B.1 Assessment framework



B.2 National Gas Objective

In accordance with the two terms of reference, the AEMC must have regard to the NGO in undertaking these reviews. The NGO is set out in section 23 of the National Gas Law and states:

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

The NGO is structured to encourage energy market development in a way that supports the:[123]

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 has considered the long-term interests of all consumers of natural gas throughout this review. The AEMC notes that there are numerous types of consumers of natural gas in the Australian economy, including: residential and commercial users; industrial and manufacturing users; gas fired generators; and LNG producers.

As with all rule changes and reviews, when applying the NGO we will have regard to the following set of high-level principles:

- competition and market signals will generally lead to better outcomes than centralised planning and regulation, as competing energy businesses have an incentive to meet consumers' needs efficiently;

- where it is required, regulation should be targeted, fit-for-purpose, provide incentives that attempt to imitate the outcomes of a workably competitive market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address;

- 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.

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

B.3 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference for the East Coast review, 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 requested that the AEMC 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:[124]

> "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:[125]

1. **Encouraging competitive supply:**
   - (a) Improvements to the regulatory and investment environment so that gas supply is able to respond flexibly to changes in market conditions.
   - (b) A "social licence" for onshore natural gas development achieved through inclusion, consultation, improving the availability and accessibility of factual information relating to resources projects, and rigorous science to ensure that communities concerns are addressed.
2. **Enhancing transparency and price discovery**:
   - (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.

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

125 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/

3. **Improving risk management:**

   (a) Liquid and competitive wholesale spot and forward markets for gas that provide tools for participants to price and hedge risk.

   (b) Access to regional demand markets through more harmonised pipeline capacity contracting arrangements which are flexible, comparable, transparent on price, and non-discriminatory in terms of shippers' rights, in order to accommodate evolving market structures.

   (c) Harmonised market interfaces that enable participants to readily trade between locations and find opportunities for arbitrage and trade.

   (d) Identified development pathways to improve interconnectivity between supply and demand centres, and existing facilitated gas markets, which enable the enhanced trading of gas.

4. **Removing unnecessary regulatory barriers:**

   (a) Regulation of gas supply and infrastructure is appropriate and enables participants to pursue investment opportunities, in response to market signals, in an efficient and timely manner.

While stream 1, "encouraging competitive supply," is largely outside the scope of the AEMC's reviews, it provides necessary context to our more thorough consideration of issues relating to streams 2 to 4.

Overall, the Vision provides the Commission with a high level policy statement to guide its analysis through the review. It does this by setting out the broad direction that gas market development should take in order to meet the NGO. The elements that make up the Vision can be considered the "means" of promoting the overarching objective – the NGO – through increasing the efficiency of the gas market, for the long-term benefit of consumers of natural gas services.

B.4 Characteristics of a well-functioning gas market

While the NGO serves as the overarching objective and the Vision provides the high level policy direction, the AEMC is also guided by a number of attributes that represent well-functioning, workably competitive markets.[126] These are:[127]

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126 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."

127 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.

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.

C Responses to questions posed by the Victorian Government

On 13 May 2016 the Victorian Government responded to the DWGM Review draft report and extended the timeframes for the DWGM Review. The purpose of the extension was to enable the AEMC to provide a more detailed design for the recommendations and enable further stakeholder consultation.

As part of the extension, the Victorian Government requested the AEMC to provide the following:

- An assessment of the costs and benefits. The AEMC engaged PwC to assess the costs and benefits of the proposed recommendations (see section 3.2.7).
- An assessment of the potential implications for reform to the DWGM in the unlikely event that broader east coast gas market reform stalls. In light of the decisions taken by the COAG Energy Council at its August 2016 meeting, the Commission considers it is unlikely that broader east coast gas market reform will stall. However, the Commission also considers that the benefits of reforming the DWGM are such that this should be done in any event (see section 3.2).
- Responses to questions raised by stakeholders. A list of questions was provided by the Victorian Government and responses to these questions are provided in Table C.1 below.

Table C.1 AEMC responses

Question	AEMC response
(i) How can the proposed system of entry and exit rights and the balancing market generate the necessary level of liquidity to support a well-functioning derivatives market given there are few gas producers in Victoria?	The intent of the recommendations is to improve the market for physical trading. As liquidity grows, this may support the development of a derivatives market. The target model will encourage the trading of gas (and facilitate liquidity) by: • retaining a virtual hub that concentrates buyers and sellers and allows gas to be traded independently of its location; • incentivising market participants to trade by making them primarily responsible for managing their own imbalances position; • establishing exchange-based trading, which would provide low cost, anonymous trading of standardised products that reflect participant needs; and • enabling financial traders to participate in the market. However, to minimise any risks that liquidity does not develop (particularly at market start while confidence in the market builds) the Commission is recommending several transitional measures to stimulate liquidity. See section 3.3 and Chapter 7.

Question	AEMC response
(ii) Given that the National Electricity Market (NEM) has produced a derivatives market, why has this not occurred in the Victorian DWGM?	Driven in large part by the physical characteristics of gas and the demand for gas, the design of the DWGM spot market is considerably more complex than the NEM spot market. In particular, the DWGM's multiple pricing schedules do not appear to be consistent with the development of financial risk management products. Were a financial derivative to be referenced to only the 6.00am price, then an individual participant's exposure to a change in the market price over the course of the day would not be hedged. Uplift payments represent an additional price risk. While congestion uplift can be hedged by holding AMDQ rights, this protection only exists when a market participant is injecting gas, and hence is not available to parties solely consuming gas. See section 2.4.1.
(iii) How reliably can imbalance costs be allocated differently to market participants (to create the expected incentives on market participants to balance their positions)?	The target model has been designed to allow the system operator to assign imbalance costs to the market participants who caused the imbalance. Under the target model, market participants would have primary responsibility for balancing their own positions. The system operator would have a residual balancing role if the system as a whole is projected to be out of balance. The system operator would purchase gas and pass those costs onto any market participant who contributed to the system being out of balance. This creates an incentive for participants to balance their positions. If these costs were recovered on an average cost basis, the charges levied on causers would exactly match the costs incurred by the system operator in taking residual balancing actions. See section 5.3.4. Other costs related to the management of system constraints are discussed in section 5.4.
(iv) How can gas pipeline capacity hoarding be prevented in the proposed system of entry and exit rights?	The target model contains a number of features designed to prevent market participants from hoarding capacity. Access to entry and exit capacity (apart from distribution points) would primarily be through auctions. Auctions allow parties equal opportunity to bid for baseline and above baseline capacity, and for capacity to be allocated to the participant who values it most. Some capacity would be held back for shorter term sales, so capacity would be continually offered to the market. Distribution points would be allocated dynamically, so participants would be unable to hoard capacity. Secondary trading of capacity would be allowed through bilateral arrangements or facilitated through an exchange. In addition, there would be a day-ahead auction of contracted but un-nominated capacity (use-it-or-lose-it). This mechanism would frustrate any attempt to hoard capacity by re-offering un-nominated capacity to the market. See section 6.4.3.

Question	AEMC response
	Under the current target model there would remain the possibility that parties may nominate to use capacity but then not do so (i.e. nominate in bad faith). In further developing the reforms, the GMRG could consider a regime to address issues relating to late (re)nominations, or not flowing consistently with nominations (see section 5.4).
(v) How will issues of market power be addressed where there are limited players at individual entry and exit points?	The response to question (iv) above explains the mechanisms in the target model designed to allocate capacity to the participant who values it most, facilitate secondary trading of capacity, and the re-offering of un-nominated capacity back to the market. The Commission considers that entry points are likely to be sufficiently large and liquid to prevent individuals from exercising market power. Some of the smaller exit points (except distribution exit points where capacity would be dynamically allocated) may involve one or few parties. However, the target model includes incentives to make capacity available. If a participant exercises its market power by acquiring but not nominating to use capacity, that capacity would be auctioned back to the market (use-it-or-lose-it) and the participant would not be compensated. This provides an incentive to trade any unused capacity ahead of the gas day. Capacity auctions would have a zero reserve price, which may provide opportunities for other participants to obtain low cost capacity. A consequence of auctioning un-nominated capacity is that, so long as capacity at an exit point is sufficient to meet gas commodity demand at the exit point, capacity will be available to the participant wishing to use that capacity. For example, if a retailer has purchased all of the capacity at an exit point that services one large user, and the large user at the exit point changes retailer or enters into its own GSA, the retailer would no longer be nominating exit capacity at that point and the capacity would become available for another participant to purchase, albeit potentially on a day ahead basis. If there is more demand at an entry or exit point than available capacity, the target model enables participants to signal additional investment at that point (see section 6.5).
(vi) Will the proposed system of entry and exit rights create barriers to entry and how does the proposed model compare with the existing DWGM in terms of barriers to entry?	The target model will require market participants to obtain entry rights to inject gas into the DTS, or exit rights to withdraw gas. While this is not currently required of market participants, entry and exit rights provide participants with certainty that they will have access to the system and provides signals for investment in pipeline infrastructure. This is a small but important trade-off. The target model includes mechanisms to make capacity rights available to those who value it most (discussed above) and capacity rights at distribution points would be dynamically allocated (i.e. no barriers to entry). Also, although market participants do not need AMDQ(cc)

Question	AEMC response
	in the current DWGM, they are valuable to have and not easy to obtain. The Southern Hub model includes improved processes for obtaining entry and exit rights in comparison.
(vii) Do existing entry-exit trading systems that are applied in other jurisdictions feature participation by small retailers?	Yes. The gas system in Great Britain is set up as an entry-exit model. There are currently 37 active small and medium sized licensed suppliers (most of which provide both electricity and gas) and there have recently been a number of new entrants.[128] Another example is the Netherlands, which has an entry-exit model that has many similar elements to the Southern Hub model, has 53 active gas retailers, of which 25 per cent entered the market in the previous few years.[129] Many of the European countries that have well developed entry-exit gas systems have small retailers participating in those markets.
(viii) Are there any trade-offs between economic efficiency and system security?	The Commission does not consider the recommendations trade off system security in favour of economic efficiency. Economic efficiency is the key principle underlying the NGO and system security forms part of this. However, the recommendations include some trade-offs between simplicity and cost reflectivity. For example, when considering the most appropriate balancing mechanism: • Daily balancing would only require participants to balance their positions once a day. AEMO would likely need to balance the system to maintain security during this time and have to socialise these costs. • Hourly balancing would require participants to balance their positions every hour. There would be less chance of AEMO needing to balance the system, but the balancing for participants would be unnecessary and costly. Continuous balancing is slightly more complicated than daily balancing, but costs can be readily allocated to causers. Costs are likely to be more efficient and reflective of the risks because balancing only occurs when system security is at risk, unlike hourly balancing.
(ix) How will the Southern Hub improve gas procurement options for gas users and small retailers?	Under the target model, market participants will have greater flexibility to purchase gas through three mechanisms: • from the exchange, where different products would be available; • bilaterally, using OTC contracts; and • long-term GSAs, either at an injection point (e.g. Longford) or at the hub (which may provide greater liquidity for traders).

128 Ofgem, *Retail Energy Markets in 2016*, pp. 9-10.

129 ACER, *ACER Market Monitoring Report 2015*, pp. 52-56.

D Summary of required, preferred and suggested design features

Table D.1 Commodity trading

	Required design features	Preferred design features	Suggested design features
Recommendation 1: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.			
Unbundling from capacity	• Commodity sold at the hub would be unbundled from capacity rights. These would be sold separately.		
Commodity trading unbundled from capacity	• The existing mandatory daily gross pool scheduling process for trading gas for the upcoming day would be replaced by voluntary, continuous trading. • One of the options for trading would be an exchange similar to the GSH design. • Market participants would be able to trade outside the exchange (bilaterally or OTC) within the DTS, but this would now be at the virtual point.	• The exchange would utilise the existing GSH trading platform (Trayport). • The exchange would utilise existing GSH credit and risk management processes.	
Virtual hub	• The Southern Hub would be a virtual hub, meaning: — all gas inside the hub is fungible; — trading occurs at a 'notional point'; — market participants deliver gas to the hub and receipt gas from the hub; — the system operator is responsible for managing flows within the hub.		• More granular trading locations may be required for the purposes of congestion management by the system operator.

	Required design features	Preferred design features	Suggested design features
Commodity products	• Products available through the hub would be determined in close consultation with market participants.	• Products initially provided could be based on those offered at the GSH.	• Products for more immediate delivery may be required by: — the system operator for network security management; and — market participants for balancing.

Table D.2 Balancing

	Required design features	Preferred design features	Suggested design features
Recommendation 2: Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.			
Continuous balancing	• Each market participant would have primary responsibility for maintaining a reasonable balance between their own supply and demand during a gas day, and between one gas day and the next. • There would be financial and regulatory incentives to encourage market participants to remain in reasonable balance. • Market participants would not be required to be in balance at any pre-determined time, but would be	• Market participants would be able to choose to have an imbalance carried from one gas day to the next.	

	Required design features	Preferred design features	Suggested design features
	subject to residual balancing action charges if they were out of balance at the time when residual balancing action is taken by the system operator. • Market participants would nominate their expected injections and withdrawals as hourly flows at specific locations on the virtual hub and notify the system operator of any trades undertaken at the virtual hub. • The system operator would determine each market participant's imbalance position hourly, and publish it shortly thereafter. • A near real time (NRT) allocation methodology would be used to determine each market participant's imbalance position. • There would be a reconciliation process to account for the difference between a market participant's NRT allocation and their actual allocation determined after six months. • There would be comprehensive information provision to market participants to enable them to monitor their imbalances and other market parameters.		

	Required design features	Preferred design features	Suggested design features
Residual balancing	• The system operator would take residual balancing action if market participants are collectively out of balance to the extent that system security is affected. • The system operator would set the linepack limits at which it would take residual balancing action before the start of every gas day. • The system operator would determine and publish an hourly system balance signal. • The system operator would take progressive residual balancing action if the system balance signal exceeds the linepack limits during the day. • The system operator would take residual balancing action using the trading exchange at the virtual hub. • Market participants who have contributed to the need for a residual balancing action would be allocated a portion of costs for residual balancing action, and a portion of the gas that was bought or sold.		• A projected system balance signal would be used to determine the need for residual balancing action.

	Required design features	Preferred design features	Suggested design features
Management of system security and emergencies	• The system operator would be responsible for undertaking a variety of actions to maintain system security not related to system wide balancing. • The system operator must establish emergency management procedures to manage emergency situations affecting the Southern Hub that are consistent with arrangements for the DWGM. In accordance with these emergency management procedures, the system operator may make directions to market participants to maintain system security.	• Actions that the system operator would take to maintain system security not related to system wide balancing include: — buying or selling gas through the exchange at specific locations; and — buying back capacity rights from market participants.	

Table D.3 Capacity

	Required design features	Preferred design features	Suggested design features
Recommendation 3: The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.			
Capacity calculation			
Baseline capacity	• Baseline capacity would be calculated through a transparent process with the pipeline operator proposing the level of baseline capacity and the AER approving such level after consultation with industry participants.		• Baseline capacity would be defined on a seasonal basis in order to maximise the release of firm capacity during the year.

	Required design features	Preferred design features	Suggested design features
	• Baseline capacity would be calculated with the aid of load flow modelling software, taking into account forecast demand and planning standard.		
Above baseline capacity	• Above baseline capacity would be determined by AEMO on a short-term basis, based on the expected pattern of flows and operational constraints on the network each gas day. • Above baseline capacity would be calculated in a similar manner to the baseline capacity, with the aid of load flow modelling software.		
	Capacity products		
Standardised capacity products	• Entry, exit and counterflow products should be developed. • Firm and interruptible products should be developed, with firm capacity available for a range of contract tenors and interruptible entry and exit capacity only available on a day-ahead and within-day basis. Interruptible counterflow capacity should be available for all contract tenors.	• Renomination rights should be included in the standardised product to enable market participants to manage intra-day changes, but limits are likely to be required to facilitate the release of contracted but un-nominated capacity. • Operational, prudential and other contract provisions should, where relevant, be based on the standardised provisions that the GMRG has been accorded responsibility for developing for contract carriage pipelines.	• Contract lengths would include: — longer-term products: quarterly products for up 10 or 15 years (i.e. 40-60 quarters) and monthly products for the next year (i.e. 12 months); and — shorter-term products: month-ahead, weekly, day-ahead and within-day products.

	Required design features	Preferred design features	Suggested design features
	• Standardisation would occur in consultation with industry and provide for standardised entry / exit / counterflow points (or zones if appropriate), contract lengths, capacity metrics (GJ/d or GJ/h) and other conditions. • To the extent relevant, the standardised products should mirror the commodity products to be sold through the exchange.		• If there is sufficient demand for an hourly product, and if feasible, capacity should be defined on an MHQ basis, otherwise it should be defined on an MDQ basis with either a flat hourly flow or a minimal amount of hourly flexibility (e.g. a 1.1 hourly load factor) and consideration given to whether additional hourly flexibility can be provided to those that require it.
Capacity release and allocation mechanisms			
Existing baseline capacity	• There would be auctions to release existing baseline capacity at entry points, and interconnection, storage and direct connect exit points. • Existing baseline capacity at distribution exit points would be dynamically allocated. • The AER would be responsible for approving reference tariffs (which would form the basis for the reserve prices used in the auctions) and determining how any over or under recovery of revenue or prices be treated.		• The auction of longer-term products should take the form of an ascending clock uniform price auction, if it is feasible to do so. If this is not feasible a sealed bid uniform price auction should be considered. • The auction of shorter-term products should take the form of a single round sealed bid uniform price auction. • A fixed proportion of the baseline capacity should be reserved for shorter-term auctions (e.g. monthly, month ahead, day ahead or within day products).

	Required design features	Preferred design features	Suggested design features
Transitioning AMDQ and AMDQ cc		**AMDQ** • Tariff V AMDQ and Tariff D AMDQ holders at distribution exit points would be automatically allocated firm capacity through the dynamic allocation process. • Tariff D AMDQ holders at non-distribution exit points would have the option to acquire an allocation of firm capacity rights up to their current AMDQ holding for as far into the future as capacity is made available. Those Tariff D customers that are supplied by a retailer would be able to assign the firm rights to the retailer for the duration of their retail contract. **AMDQ cc** • A similar approach to that proposed for Tariff D AMDQ holders at non-distribution exit points would be applied but capacity could only be obtained for the remaining term of their AMDQ cc contract.	
Above baseline capacity	• Above baseline capacity would be allocated through a day-ahead auction, with capacity rights to be offered on an interruptible basis.		• The auction would be a single round sealed bid auction with a zero reserve price.

	Required design features	Preferred design features	Suggested design features
	• The capacity would be released the by system operator at entry and exit points where baseline capacity has been fully sold. • Revenue from the auction would accrue to AEMO to offset unallocated congestion costs.		
Measures to encourage the release of secondary capacity			
Auction for contracted by un-nominated baseline capacity	• There would be a daily, day-ahead auction for contracted but un-nominated capacity at points with contractual congestion. • The auction would happen shortly after a specified nomination cut-off time. • The auction would have a reserve price of zero.	• The auction would sell capacity in firm and interruptible components, with the interruptible component only released when the firm component is sold. The original owner would retain the right to increase its nominations where its capacity has not been sold on an firm basis. • The auction would be a single round auction with a first price rule, where bidders pay the value of their winning bid, to reduce complexity.	
Secondary capacity trading	• An electronic exchange would be created that would enable market participants to trade secondary capacity on an anonymous basis. • Trades carried out through the capacity trading platform would be given effect through an operational transfer.		• Trades conducted outside the capacity trading platform should be advertised ahead of time on the capacity trading platform listing service.

	Required design features	Preferred design features	Suggested design features
	• Information on all secondary trades, including the price of the trade plus any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties would be published.		
Investment in new baseline capacity			
New baseline capacity	• Investment in new baseline capacity for entry and exit points (other than distribution connected exit points) would be signalled by market participants' commitment buy entry or exit rights. • Investment to support flows to distribution connection exit points would be determined through the same approach that is currently used.	• Hybrid open season / integrated auction would be used to signal market participants' commitment buy entry or exit rights provided by a capacity expansion. This would be conducted at least every two years.	

Table D.4 Transition

	Required design features	Preferred design features	Suggested design features
Recommendation 4: Market trials should be undertaken to determine the requirement for, and design of, transitional measures that may be appropriate to help stimulate liquidity in the commodity market and mitigate against the negative impacts of changed market arrangements for market participants.			
Market trials	• Market trials should be undertaken in accordance with recommendation 4. The trial should be sufficiently sophisticated that the GMRG can draw meaningful conclusions.		
Financial tolerances		• Transitionally, financial tolerances should be applied for imbalances up to a threshold, which would provide market participants with financial protection against residual balancing action costs. • Residual balancing action costs within the tolerance should be socialised across market participants.	• Financial tolerances should be applied on an absolute basis to all market participants.
Daily balancing		• Transitionally, there should be daily balancing discipline on market participants in addition to a continuous balancing regime within the day.	• The daily balancing discipline on market participates should be achieved through a daily balancing regime, as opposed to a linepack usage charge.
Other transitional measures		• Other transitional measures, such as a market maker obligation, should be considered for subsequent implementation if the above transitional measures are insufficient.	

	Required design features	Preferred design features	Suggested design features
Implementation of transitional measures		• Transitional measures should be in effect for a relatively short period (e.g. less than 18 months) • A timetable, or triggers, for rolling back the transitional measures should be clearly specified to provide market participants with clarity around their upcoming responsibilities.	• AEMC's biennial report on market liquidity may be used to identify whether triggers for removing transitional arrangement are met.

Table D.5 Implementation

	Required design features	Preferred design features	Suggested design features
Recommendation 5: The COAG Energy Council should task the Gas Market Reform Group (GMRG) to implement the Commission's recommended reforms to the DWGM (Recommendations 1-4) and the corresponding required design features. The GMRG should also take into account any preferred and suggested elements outlined by the Commission.			
Reform body	• GMRG would be responsible for progressing reforms to the DWGM. • SCO and/or the Victorian Government should provide leadership and direction to guide implementation.	• The structure of the working group should facilitate participation by Jurisdictional officials.	
Reform task	• GMRG should propose NGL changes to the COAG Energy Council and NGR changes to the AEMC to implement the reforms.	• The GMRG should work closely with AEMO to identify new procedures or amendments to existing procedures.	

Abbreviations

ACCC	Australia Competition and Consumer Commission
ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	authorised maximum daily quantity
AMDQ cc	AMDQ credit certificates
AMIQ	authorised maximum interval quantity
ASX	Australian Securities Exchange
CFO	call-for-order
COAG	Council of Australian Governments
Commission	See AEMC
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EU	European Union
FCFS	first-come-first-served
GMRG	Gas Market Reform Group
GSA	gas supply agreement
GSH	Gas Supply Hub
LNG	liquified natural gas
MDQ	maximum daily quantity
MHQ	maximum hourly quantity
MP	market participant

NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NRT	near real time
NTS	National Transmission System
Ofgem	Office of Gas and Electricity Markets
OTC	over-the-counter
PARCA	Planning and Advanced Reservation of Capacity Agreement
POS	position
QNI	Queensland – New South Wales Interconnector
RBA	residual balancing action
RBB	residual balancing bands
SBS	System Balancing Signal
SCO	Senior Committee of Officials
SEA	Service Envelope Agreement
SEA Gas	South East Australia Gas Pipeline
SRMC	short-run marginal cost
STTM	Short Term Trading Market
UAFG	unaccounted for gas
UIOLI	use-it-or-lose-it