REVIEW

Australian Energy Market Commission

FINAL ASSESSMENT OF ALTERNATIVE MARKET DESIGNS

Review of the Victorian declared wholesale gas market

30 June 2017

Reference: GPR0002
Final assessment of alternative market designs

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: GPR0002

Citation

AEMC 2017, *Review of the Victorian declared wholesale gas market*, Final assessment of alternative market designs, 30 June 2017

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.

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.

In light of the changes underway in the east coast gas sector, the Council of Australian Governments (COAG) Energy Council formulated a vision for Australia's future gas market. 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.

Against this background, the 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).[1]

The Commission provided a final report to the COAG Energy Council on 30 June 2017 that investigated the issues facing the current DWGM and set out the Commission's recommendations to address these issues (DWGM final report).[2] The Commission made a set of short term and longer term recommendations to reform the DWGM.

The DWGM final report was published with two accompanying reports:

1. The final technical report provides a detailed design of the long-term target model for the Victorian market.[3]

2. This final assessment of alternative market designs provides a final assessment of the reform options that were considered but not recommended by the Commission and are not discussed in the final report. This builds upon the options set out in the March 2017 options paper.[4]

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

2 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Report, 30 June 2017.

3 AEMC, *Review of the Victorian declared wholesale gas market*, Final Technical Report, 30 June 2017.

4 AEMC, *Review of the Victorian declared wholesale gas market*, Assessment of Alternative Market Designs, 30 March 2017.

This final assessment of alternative market designs should be read in conjunction with the two other reports.

1.1 Assessment of alternative market designs

In March 2017 the Commission released an options paper that set out 15 different options for reforming the DWGM, or parts of the DWGM. For each of the options, the Commission provided a description of the option and a preliminary assessment, for feedback by stakeholders.

Figure 1.1 below provides a diagrammatic representation of the options from the March 2017 option paper.

Figure 1.1: options for alternative market designs

Of the 15 options, six (grey in the diagram) have formed part of (or are a variety of) the Commission's short term recommendations listed above. Specifically:

- Recommendation 1 is an alternative form of the options on a 'transmission constrained pricing schedule' and 'simplified uplift'. Both of these options are discussed in the final report.
- Recommendation 2 is to introduce 'forward trading within the DWGM' and the similar alternative 'forward physical trading outside the DWGM' is discussed in the final report.

- Recommendation 3 includes the introduction of 'exit AMDQ' and 'improving AMDQ allocation and trading'.

The remaining options (blue in the diagram) are not discussed in the final report and are instead the topic of this final assessment of alternative market designs.

In addition, the March 2017 options paper canvassed several 'other' options that stakeholders had put forward that did not seem to address the objectives of the review.[5] Some of the suggestions that the Commission considers may have some merit are discussed in the final report.[6] The remaining other options are not discussed at length in this final assessment of alternative market designs.[7]

1.2 Structure of this assessment of alternative market designs

Any gas market design must address the:

- trading of gas commodity
- transport of that gas (that is, access to pipeline capacity).

The DWGM implicitly allocates pipeline capacity through the gas commodity market. In contrast, the target model put forward by the Commission separates these two elements and involves the continuous voluntary trading of gas commodity, and explicit entry and exit capacity rights to access the DTS, allocated through a market separate to the gas commodity market. Fuller descriptions of the DWGM and target model are provided in chapter 2 of the final report[8] and the accompanying final technical report[9] respectively.

As such, the final assessment of alternative market designs is structured as follows:

- chapter 2 covers options to improve gas commodity market
- chapter 3 covers options regarding pipeline capacity access.

---

5 AEMC, *Review of the Victorian declared wholesale gas market*, Assessment of Alternative Market Designs, 30 March 2017, Chapter 7.

6 The suggestion to review the market floor price is discussed in section 4.1 of the final report. The suggestions to publish linepack adjustments, provide more timely market data, and publish pre-dispatch schedules are discussed in section 4.4 of the final report.

7 To briefly summarise these options: the suggestion to review the market clearing engine was not supported by those stakeholders which comment on this option; the suggestion to re-centralise market demand forecasts was supported by some stakeholders and the Commission suggests that if stakeholders consider it would provide benefits to raise it with AEMO in a consultative forum to be further considered.

8 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Report, 30 June 2017, chapter 2.

9 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Technical Report, 30 June 2017.

2 Gas commodity market options

A key issue with the existing DWGM identified throughout this review is the inability for market participants to effectively manage price risk, which is now particularly important in light of recent and likely future increased volatility in gas flows and prices.[10]

The following options are reforms to the way gas is traded in the DWGM, which would allow participants to better manage their risks through either improved physical trading, or the development of a financial derivatives market.

These options are:

1. introducing out-of-balance intra-day schedules
2. requiring participation in the DWGM
3. introducing forward trading with a net daily gas market.

A description of these three options, and the Commission's final assessment, is given below.

2.1 Discrete intra-day schedules to manage system balancing

In the DTS (as with all gas networks and pipelines), supply and demand do not need to be in balance instantaneously. Linepack is used to manage instantaneous differences between supply and demand, increasing or decreasing the pressure within the pipes. As such, AEMO typically schedules gas in the DWGM such that supply and demand balance over the course of a day, reflecting the daily pattern of gas demand in Victoria.

When implemented in 1999, the DWGM had a single, daily price, reflecting the typical daily balancing of the DTS. In 2007, five schedules throughout the day were introduced which are each a balance-of-day schedule. That is, the 6.00am schedule is a 24 hour schedule (6.00am-6.00am), the 10.00am schedule is a 20 hour schedule (10.00am-6.00am), and so on. Each balance of day schedule aims to get back to an end-of-day linepack target, so that, taking the day as a whole, supply and demand balances.[11] The introduction of the multiple pricing schedules was to allow for more granular pricing and scheduling.

However, during this review, stakeholders identified that balance-of-day schedules may be inhibiting the uptake of trade in financial derivatives.[12] In particular:

10 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Report, 30 June 2017, section 2.2.

11 Other than in cases where the end-of-day linepack target is different today from yesterday, because AEMO intends to increase or decrease the overall linepack of the system between days.

12 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, p. 23.

- 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 to 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.

2.1.1 Description of the option

In this option, multiple schedules throughout the day would be retained (so as to retain the benefits of more granular pricing and scheduling), but each schedule period would be for the time up to the next schedule (that is, the schedules would be discrete and not be balance-of-day). For example, the 6.00am schedule would be for four hours until 10.00am, and so on.

There is no physical requirement for each schedule to be in balance, and to require it to be so would be an inefficient use of the linepack capacity of the DTS. Instead, AEMO would schedule more or less gas to be injected than forecast to be withdrawn for the upcoming schedule. Any excess gas would be stored in linepack and any deficit of gas would be met from stored linepack, in order to meet pre-determined end of schedule linepack targets (which would vary throughout the day). Put another way, each schedule would be in balance once the surplus or deficit gas scheduled by AEMO from and to linepack is taken into account.

For example, during overnight schedules, when demand is typically at its lowest, AEMO would schedule additional gas to be injected from the market and increase linepack, ready to meet a later deficit in gas in the afternoon schedules when demand is highest.

While AEMO would store and release the same quantity of gas from linepack throughout the day in order the return the system to being in balance over the day, the price for gas used to increase linepack is likely to differ from the price for gas released back to the market from linepack. All else equal, we would expect linepack to increase when the price for gas is low (when demand is low) and linepack to decrease when the price for gas is high (when demand is high), creating a positive settlement residue. In effect, AEMO is using the linepack of the DTS to arbitrage prices between times of lower demand (for example, night time) and times of higher demand (for example, daytime, particularly the evening peak).

AEMO's demand for gas to increase linepack overnight will increase the market price. Similarly, AEMO's supply of gas from linepack in the evening peak will decrease the market price. This should have a smoothing effect on the prices throughout the day.

AEMO could return the settlement residue to market participants through reduced fees. Alternatively, AEMO could auction rights to the "inter-temporal settlement residue" (ITSR), in the same way that there are settlement residue auctions in the NEM between regions for inter-regional settlement residue (IRSR).

In this way, there would be prices for each schedule throughout the day, removing the identified barrier to derivatives trade that arises through multiple balance-of-day pricing schedules.

Deviation payments would be unaffected by the changes outlined in this option. AEMO would continue to schedule gas in a subsequent schedule to balance any deviations from scheduled injections/withdrawals and actual injections/withdrawals in the previous schedule, with the associated costs/revenues being met by deviating market participants in the form of deviation payments.

A market for linepack

A more sophisticated version of this option would be that instead of AEMO determining linepack usage and allocating the resulting arbitrage profits back to market participants, linepack could be allocated to market participants directly through the DWGM.

Under this sub-option, market participants could specify in their bids/offers to "withdraw"/"inject" from/to linepack. In effect, linepack is treated like another injection/withdrawal point in the DTS, and each market participant would have a linepack account. Assuming linepack to be an injection/withdrawal "point", the supply and demand would balance within each discrete schedule. The price for withdrawing to or injecting from linepack would be determined through the DWGM (that is, it would be the DWGM market price).

We would expect for projected high demand days, market participants would seek to withdraw significant quantities of gas into linepack the night before (at presumably fairly high gas prices in comparison to typical night-time prices), in anticipation of even higher gas prices in the next evening. In this way, the market, as opposed to AEMO, would determine how linepack is used throughout the day.

Again, we would expect smoothing of prices throughout the day due to increased demand for gas into linepack overnight and increased supply of gas from linepack in the evening. To the extent market participants make accurate forecasts, we would expect that market participants would stop withdrawing into linepack when the expected future price equals the current price (that is, when the expected price differential has been arbitraged away).

Access to linepack capacity would be determined dynamically through the DWGM, in the same way that access to transportation capacity is determined through the DWGM currently.

At times, we might expect that demand for linepack capacity exceeds the physical capacity of the system, in the same way that demand for transportation capacity sometimes exceeds the physical capacity. In these instances, market participants might bid at the market price cap, which means that the DWGM would not be able to ration it. It might instead be rationed using pre-allocated tie-breaking rights (analogous to the way AMDQ tie-breaks transportation constraints). The number of pre-allocated tie-breaking rights would be determined with regard to the physical capacity of the system (as the number of AMDQ rights are now) and then auctioned, perhaps in tranches of different tenures, consistent with this review's recommendations for AMDQ.[13]

This approach has strong parallels to the current allocation of transportation capacity through the DWGM and non-firm transportation capacity rights.

The auction for tie-breaking rights to inject/withdraw from/to linepack would provide (weak) signals for investment in linepack capacity, in the same way that AMDQ cc auctions provide weak signals for investment in transportation capacity.

2.1.2 Stakeholder submissions

Only a limited number of stakeholders provided commentary in their submissions on this option. However, those that did primarily raised concerns, instead of supporting the option. No stakeholders unreservedly supported this option.

AEMO did not consider the option would support the development of financial derivative products, as "having multiple firm within day prices will create a basis risk when compared to the current futures product that converges to the 6am schedule, which covers the entire gas day."[14]

Stakeholders noted the complexity of the option. They considered discrete pricing schedules and a linepack market would result in participants needing to pay more attention to balancing and being more active in gas trading throughout the day. Some stakeholders considered that this would be an administrative burden, and their underlying commercial and operational structures would need to change to accommodate this.[15]

AEMO also considered that having discrete intra-day schedules may inhibit interregional trade because the DWGM would then be operating on a different time

13 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Report, 30 June 2017, section 4.3.

14 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 3.

15 Submissions to the assessment of alternative market designs: ERM, p. 7; EA, p. 5; MEU, p. 14; AEMO, Appendix B, p. 3.

basis (four/eight hourly instead of balance of day) which may create additional risks and complexity for those transporting gas across jurisdictions.[16]

AGL considered this option could create a security of supply risk. This is because there is limited linepack and it may be too risky to only schedule the market four/eight hours ahead of time instead of for the balance of day.[17]

ERM questioned how AEMO's performance would be measured with regard to the settlement residues from linepack management, if they were responsible for managing linepack.[18]

2.1.3 Assessment of the option

Under the first, less sophisticated version of this option, if AEMO were to determine the quantity of gas to store and release from linepack itself, a key consideration would be how AEMO would determine the appropriate end of schedule linepack target, and hence how much surplus/deficit gas to schedule.

Currently, AEMO implicitly sets end of schedule linepack targets, given the amount of gas it schedules to be injected and withdrawn within each four or eight hour period. It does this based on forecasts of future gas requirements for the balance of the day, which are in turn informed by market participants' bids and offers for the balance of the day. If market participants were only required to make bids and offers for a discrete schedule (that is, the next four or eight hours) and AEMO were to continue to determine the end of schedule linepack targets, AEMO would have less information on which to make these decisions, potentially resulting in less efficient use of linepack than currently.

Under the second, more sophisticated version of this option, even if there were a market for linepack, AEMO would need to determine how much linepack to make available to the market participants. In contrast to the first sub-option, this sub-option could lead to a more efficient use of linepack than is currently the case because it is based on market participants' valuations of linepack. Nevertheless, AEMO would still need to set limits on the amount of linepack that could be made available to the market, and so constrain off market participants where collectively demand for linepack exceeds these limits. Setting the limits could be achieved through AEMO modelling, which might include consideration of the trade-off between linepack capacity and transportation capacity.

Under both of the sub-options described above, market participants would be able to manage their exposure to the price in each of the five schedules throughout the day by purchasing derivatives corresponding to each of those schedules. Nevertheless, to fully manage their exposure to the market price in any individual schedule, market participants would need to accurately forecast their gas requirements and buy/sell

---

16 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 3.

17 AGL, Submission to the assessment of alternative market designs, p. 10.

18 ERM, Submission to the assessment of alternative market designs, p. 7.

sufficient derivative contracts. As with currently, any forecasting error in this regard would lead to exposure to the market price – as noted by AEMO in its submission.[19]

Market participants will therefore still need to estimate their gas requirements in each schedule. If a market participant were to be inaccurate in this regard and so not buy/sell the appropriate quantity of derivative hedges, it will be exposed to the price in any individual schedule. This is exactly the same situation to now, whereby a market participant is not exposed to anything other than the 6.00am price unless it inaccurately forecast its gas requirements at the start of the day. It is therefore **not clear whether this approach will improve market participants' ability to manage risk**.

In addition, as noted by AEMO, this option **may reduce trade between the DWGM and interconnected pipelines** because the DWGM would operate on a different time basis (four or eight hours), rather than daily/balance of day operations outside of the DWGM. Furthermore, increased complexity in the DWGM is unlikely to be conducive to inter-regional trade.

With regard to promoting upstream and downstream competition, to the extent that this option improves market participants' ability to manage risk, it may reduce barriers to market entry and reducing market concentration. However, increased complexity in the DWGM is likely to act as a barrier to new entry.

Given the complexity of this option and the likelihood that it would not improve conditions for trading financial derivatives, the Commission is not recommending this option.

2.2 Requiring participation in the DWGM

In the NEM, generators above a certain size are required to register with AEMO and sell their entire electricity output through the NEM spot market. Similarly, retailers buy almost all of their electricity through the spot market, and supply this electricity to their customers.

This contrasts with the DWGM, and may have resulted in a different market structure and risk management arrangements between the two markets.

Gas producers are not required to directly trade through the DWGM. Instead they can, and typically do, bilaterally trade physical gas with DWGM market participants outside of the DWGM. These physical trades are typically long-term in nature. It is the producers' counterparties who then participate in the gross DWGM, offering the gas they have purchased from producers to the market in order to gain access to the DTS (and very often seeking to purchase that gas back out of the market by also making matched bids, in order to reduce their exposure to the market price).

A number of market participants have identified that a potential problem with existing arrangements is that because producers are not compelled to participate directly in the

19 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 3.

DWGM and can manage their risk through long-term physical contracts there are no natural sellers of financial derivatives. As a result, market participants' ability to manage their risk is limited to long-term contracts which do not allow them sufficient flexibility to manage shorter-term variations in supply, demand and price.

2.2.1 Overview of the option

Under this option, producers and their counterparties would be required to participate in the DWGM. All physical trading of gas would have to be conducted through the DWGM, with AEMO effectively acting as an intermediary to each trade.

Defining the extent of the requirement to participate in the DWGM is an important consideration for this option, and may present significant challenges. In the NEM, all trading in the relevant states is conducted through the mandatory gross pool. In contrast the DWGM operates over the DTS - which is connected to, but does not extend over, the whole of the interconnected east coast gas transmission network.

While theoretically this option could involve extending the DWGM/DTS to cover the entire interconnected east coast gas transmission network and/or all eastern Australian states, so that all producers were captured by the requirements to participate directly in the DWGM, in practice such reform is inconsistent with:

- the terms of reference for this review, which are focussed on the Victorian DWGM
- the direction of reform recommended by the Commission for eastern Australian gas markets outside of Victoria[20], which were accepted by the COAG Energy Council[21] and are currently being progressed by the Gas Market Reform Group[22]
- retaining the contract carriage approach to pipeline access outside of Victoria, which the Commission noted is appropriate given it facilitates market-led investment, which is particularly important given the large geographic distances (and hence transmission pipeline costs) between sources of and demand for gas.[23]

Consequently, the Commission considered the following approaches to defining the requirement for producers to participate in the DWGM:

20 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, stage 2 final report, 23 May 2016, Sydney.

21 COAG Energy Council, Gas Market Reform Package Appendix A: Energy Council response to ACCC and AEMC reports, 19 August 2016.

22 See: gmrg.coagenergycouncil.gov.au.

23 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, stage 2 draft report, 4 December 2015, Sydney.

- Only those producers currently "on the edge" of the DTS (for example, at Longford) would be prohibited from bilateral trades, with other producers not being subject to the requirement.
- Expand the DTS to cover all interconnected pipelines across the whole of Victoria, including pipelines such as the SEA gas pipeline from Port Campbell to the South Australian border, and the Eastern Gas Pipeline from Longford to the New South Wales border. This would necessarily capture all producers in Victoria connected to the network.
- Extend the requirement to all producers in Victoria connected to the interconnected network, regardless of whether they are in close proximity to the existing DTS, and require them to transport their own gas to the edge of the DTS before offering it to the market.

Another consideration relates to the production of gas in Victoria where that gas is intended for delivery elsewhere (for example, gas produced at Longford for delivery in Sydney). A possible approach would be that all gas from a producer covered by the requirement would have to be offered into the DTS, and counterparties would then bid gas out of the DTS for inter-state delivery.

Scheduling in the DWGM would continue unchanged. Parties wishing to gain access to the DTS (including producers and those market participants wishing to withdraw/inject gas from/into storage such as at Iona) would offer and bid gas into and out of the DWGM, and AEMO would schedule gas on the basis of these bids and offers, and network constraints. Of course, bids and offers made by market participants may be considerably different to now, because producers would be offering directly into the market to buyers who do not have physical contracts outside of the market.

In order to transition to the new arrangements, existing physical gas supply contracts might be converted into financial derivative contracts. In time, if this option was successful, new derivative contracts would be struck between producers and consumers/retailers to manage risk, in lieu of physical contracts.

In effect, this option seeks to replicate many of the features of the NEM, with producers being required to offer gas directly through the facilitated spot market (the DWGM) and managing their spot price exposure by selling financial derivatives. The main intent of this option is that this may stimulate a liquid financial derivatives market, allowing market participants to better manage risk than currently.

2.2.2 Stakeholder submissions

Stakeholder support for this option was mixed. While some stakeholders noted the theoretical benefits, many considered the substantial implementation issues could not be overcome.

Those that supported the option (in-principle or otherwise) considered it would:

- maximise liquidity as it forces sellers into the market[24]
- support the development of financial products[25]
- increase alignment with the NEM.[26]

Also, ERM considered that requiring producers to participate in the market means that risk associated with non-delivery, injection deviations or off specification gas will be borne by sellers, who are best able to manage those risks.[27]

ENGIE suggested that the requirement to participate in the market be that all parties that wish to supply gas to customers within the DTS should be required to offer their gas into the DWGM.[28] This contrasts to the geographically defined requirements to participate in the market, as discussed above.

On the other hand, several stakeholders noted some issues with the option:

- There would be a significant impact on the existing gas supply contracts which would make legal transition to this option challenging.[29] Even transitioning existing physical contracts to financial derivatives would be challenging because each GSA is unique.[30]
- It does not provide a good signal for long term production and exploration because it would reduce the price certainty that producers need to invest.[31]

Jemena expressed some concerns that extending the DTS boundaries (and therefore the DWGM operation) could impact flows on interconnected pipelines. It was concerned that if intraday scheduling (the DWGM) was applied on one part of the interconnected pipeline, changes in intra-day scheduling could affect system security on other parts of the interconnected pipeline, such as in the STTMs. Jemena also considered it is less efficient and technically/operationally risky to have two operators on a single pipeline.[32]

Origin questioned whether a market intervention of this magnitude is warranted given the objective to drive liquidity in a financial derivatives market.[33] While AGL noted the merits of the option, it also noted that such a reform is not required to meet the objectives of the review.[34]

---

24 Submissions to the assessment of alternative market designs: ERM, p. 3; EnergyAustralia, p. 4.

25 Submissions to the assessment of alternative market designs: ERM, pp. 3, 8; EnergyAustralia, p. 4.

26 Submissions to the assessment of alternative market designs: ERM, p. 8; ENGIE, p. 2.

27 ERM, Submission to the assessment of alternative market designs, p. 8.

28 ENGIE, Submission to the assessment of alternative market designs, p. 2

29 Submissions to the assessment of alternative market designs: MEU, pp. 14-15; Origin, p. 2.

30 Submissions to the assessment of alternative market designs: Jemena, p. 4; MEU, pp. 14-15; Origin, p. 2.

31 Submissions to the assessment of alternative market designs: Jemena, p. 4; Origin, p. 2.

32 Jemena, Submission to the assessment of alternative market designs, p. 4.

33 Origin, Submission to the assessment of alternative market designs, p. 2.

34 AGL, Submission to the assessment of alternative market designs, p. 11.

2.2.3 Assessment of the option

Each of the approaches to define the requirement on producers to participate in the DWGM may have significant transitional and legal challenges. Converting existing physical gas contracts into derivative contracts may be legally challenging unless this was done on just terms. Grandfathering of existing contracts may therefore be necessary, potentially significantly diminishing or delaying the benefits of the reform. Converting existing contract carriage arrangements outside of the DTS (but within Victoria) to market carriage may be similarly challenging.

Furthermore, regardless of how the requirement for producers to participate in the DWGM is defined, this option still allows for bilateral trading on the interconnected network in the circumstances where the requirements are not met (that is, the requirement will not extend to all producers). The Commission has concerns with this, including:

- possible perverse incentives to produce/consume inside/outside of Victoria/DTS, if the requirement to participate in the DWGM was defined geographically
- problems of enforcement, if the requirement was defined with regard to the producer's intention to sell the gas for consumption in the DTS. For example, a producer may sell to a retailer on the assumption that the gas is going to be consumed outside of the DTS. Should the gas actually be offered to the DWGM by the retailer, it will be difficult to specify whether the producer has undertaken action inconsistent with the requirements of this option
- diminished benefits of the proposed model (liquidity in the derivatives market may be hindered if some physical trading is still possible).

The main rationale for this option is that by requiring participation in the DWGM, this will stimulate liquidity in the financial derivatives market as an alternative means of managing risk. Both producers and buyers of gas will be natural counterparties in this market. In turn, a liquid financial derivatives market may attract participation by non-physical players such as financial institutions.

However, the Commission is concerned that without changes to the relative bargaining power of existing market participants and producers, a similar outcome will arise in the future as now. Instead of long term physical contracts with limited flexibility for market participants to manage risk, the financial derivatives market will be similarly dominated by long term financial derivative contracts. It is **not clear that this represents a net improvement in the way existing market participants manage risk**.

With regard to the efficient use of pipeline capacity, the expansion of the DTS to cover a greater number of pipelines may increase the efficient utilisation of those pipelines, as capacity use is co-optimised with gas scheduling through the DWGM, based on market participants' bids and offers.

However, this approach **may reduce the prospect of market led investment** in the (expanded) DTS, because the free-rider problem associated with the existing market carriage approach would apply to a greater set of pipelines. In turn, this may diminish the quality of investment decision making for transmission pipelines in Victoria, and place the risk of those decisions with consumers rather than market participants.

On the other hand, this approach may allow for a **better co-ordination of scheduling of gas and electricity**, and to better manage emergencies, if the market carriage approach were to be extended over a greater proportion of gas transmission infrastructure in Victoria. For example, AEMO would be in a better position to issue directions in either market by knowing the physical status of both electricity and gas infrastructure.

To the extent the DTS/DWGM is expanded to include interconnected pipelines within Victoria, trading arrangements at those locations would change significantly. However, this approach does not appear to significantly alter trading arrangements between the DWGM and other facilitated markets in eastern Australia outside of Victoria. **Market arrangements would continue to differ** between these locations.

Given the significant complexities of implementing this option and the likelihood that it does not improve market participants' ability to manage risk, the Commission considers this option does not meet the COAG Energy Council's vision for the purposes of this review.

2.3 Forward trading with net facilitated daily gas market

2.3.1 Description of the option

This option involves allowing market participants to trade gas on a voluntary, net exchange (similar or identical to Trayport as used at the gas supply hubs (GSHs)) prior to a 'gate closure' at some point before the start of the gas day. Following gate closure, a voluntary net market would apply to enable AEMO to manage flows and system security. That is, AEMO would have primary balancing responsibility.[35]

This approach contrasts with:

- the current DWGM and recommendation 2 of this review, which use a gross market (the existing DWGM) to schedule gas on the day
- the target model, which uses a voluntary net market but provides market participants with financial incentives to be in balance; AEMO's balancing role is residual.

[35] AEMO has primary balancing responsibility in the DWGM and under the short term recommendations of this review. In the target model AEMO has a residual balancing role (see chapter 3 of the final technical report).

This approach makes most sense when coupled with firm entry and exit capacity rights as described in section 3.5. This is because AMDQ do not provide physical firm capacity rights and so would not guarantee participants that trade in advance of the cut-off point that they would be scheduled. The option in section 6.4 involves introducing firm physical capacity rights in the form of entry and exit rights plus a net capacity market to allocate spare capacity after a cut-off point. It complements this option because together they allow for forward trading and explicit capacity allocation up to a cut-off point, and then allow participants to place in bids and offers to be scheduled in a net gas and capacity market.

Market participants would be required to nominate injections and withdrawals at the time of gate closure:

- consistent with their firm entry and exit rights, and
- such that they were in balance over a defined period, 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 nominate to inject 50TJ. In this example, the market participant must have at least 50TJ of entry capacity.

Settlement of pre-agreed trades would be made at the pre-agreed price. Nominations made pursuant to meeting a market participants' own gas requirements would not require settlement (that is, if a market participant nominates to inject 20TJ and withdraw 20TJ, it will be in balance and so not need to be settled).

After gate closure, the system operator would take over all balancing responsibilities. It would meet any within-day variations between market participants' nominations and actual injections and withdrawals and managing system security by drawing from bids and offers voluntarily made by participants. This could be achieved through scheduled auctions (potentially at the same time as the current DWGM schedules) where the system operator would purchase or sell gas from market participants.

This means that it would not be mandatory for participants to arrange all or part of their gas supply (and capacity) prior to the gate closure. The net market would be used by AEMO to balance the system and allocate the unutilised capacity, so participants would also have the option to buy gas from the daily net market. However, they would not have certainty about whether they will be scheduled.

During the gas day, market participants would be incentivised to meet their nominations made at gate closure, subject to any adjustments made through the daily net market process.[36] Any deviations would be addressed by AEMO trading gas on their behalf through the scheduled auction, settled at the auction clearing price.

36 This differs from the target model, where during the gas day market participants would be incentivised to be in balance and could trade with one another, or adjust their injections or withdrawals, on an ongoing basis.

The underlying rationale for the system operator taking primary balancing responsibility 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 and optimising the use of the system. This may provide confidence to the system operator that it would be able to maintain system security regardless of the action (or inaction) of market participants.

Care would need to be taken to ensure that the "program", as defined by market participants' nominations, is consistent with the physical ability of the system. For example, market participants may make nominations which are in balance over the course of a day (say) but which are substantially out of balance for periods during the day, and which collectively may not be consistent with maintaining system security. AEMO might then have to schedule additional gas to maintain system security, but would have no means to pass these costs on to deviating market participants, because the market participants were injecting and withdrawing consistent with their nominations.

Expanding on the concepts introduced in section 2.1, market participants might be able to hold firm linepack capacity and be required to make nominations which are in balance over relatively short periods (for example, four hours), but could "inject" or "withdraw" from linepack capacity consistent with their firm linepack rights. The quantity of firm linepack rights available to the market would be consistent with the physical capability of the system.

This approach shares similarities and differences with the current DWGM, recommendation 2 of this review[37] and the target model:

- Like under recommendation 2 and the target model, and unlike the current DWGM, market participants would be able to trade gas ahead of the gas day through a facilitated market.

- Like the current DWGM and under recommendation 2, AEMO would have primary responsibility to balance the system on the day through a scheduled approach (like the DWGM), and passing balancing costs through to those market participants which deviate in the form of deviation charges

- Like the target model, and unlike the current DWGM and recommendation 2, trading of gas on the day would be through a voluntary, net exchange. However, unlike the target model, the counterparty to trades on the day would always be AEMO, which then passes the revenue/cost to deviating market participants. Under the target model, market participants would be provided financial incentives to be in balance either through trades or through varying their injections or withdrawals, with AEMO playing a residual balancing role.

- Like the target model, and unlike the current DWGM and recommendation 2, market participants would be able to hold capacity rights, purchased through a separate market, in order to nominate injections and/or withdrawals. Capacity required for pre-agreed trades and to meet a market participants' own gas requirements would effectively be reserved and no longer be allocated through the existing market carriage approach.

2.3.2 Stakeholder submissions

Not many stakeholders provided comments on this option.

However, those who did raised some potential concerns that the option could result in less liquidity in the market.[38] Their concerns mirrored their concerns with the target model, which is discussed in the final technical report.[39]

AEMO noted that this option would involve a complete re-design of the scheduling and pricing arrangements on the day, which could be costly.[40]

2.3.3 Assessment of the option

Like the target model and recommendation 2 of this review, a key potential benefit of this approach is that it may enable market participants to trade through the facilitated market ahead of the gas day, which could **improve their ability to manage risk**.

This approach may also address concerns about liquidity raised by stakeholders with regard to the target model. As a voluntary market, some stakeholders have suggested that some market participants would ignore the market and meet their varying gas requirements throughout the day by continuously adjusting their injections and withdrawals instead of trading. Stakeholders have argued that this may result in low liquidity in the market on the day, to the particular detriment of smaller market participants who do not have a large portfolio of gas from which to meet their gas requirements and currently source a large proportion of gas through purchases on the DWGM. This approach may address these concerns because market participants would be unable to unilaterally adjust their injections and withdrawals on the day to meet their own gas needs, but would instead be forced to offer/buy gas to/from the system operator which would then determine which gas is scheduled based on bids and offers.

A more liquid on-the-day market could also address AEMO's concerns about managing system security under the target model. Under the AEMO balancing approach, market participants may be more likely to engage in on the day trading through a scheduled auction because they would be unable to adjust their injections and withdrawals to meet their varying gas requirements. This may give AEMO greater

37 Recommendation 2 is the introduction of a voluntary forward gas exchange over the DTS.

38 Submissions to the assessment of alternative market designs: ERM, p. 8; Origin, p. 2; AGL, p. 11.

39 AEMC, *Review of the Victorian declared wholesale gas market*, final technical report, 30 June 2017, chapter 8.

40 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 5.

confidence that it would be able to source gas for balancing purposes as and when needed.

This option would introduce a trading mechanism similar to that at Wallumbilla and Moomba for greater than day ahead trades, but would introduce a new on-the-day trading market that would differ from the existing DWGM, the target model, and the trading model used across the east coast. Having a consistent forward trading mechanism across the east coast is expected to reduce transaction costs for market participants and **improve trading between regions**. This is also achieved through the Commission's recommendation 2 in the final report to introduce forward trading at the DTS.

However, developing and implementing a new on-the-day market is likely to be costly and this also means there would still be two market designs in operation, with potentially additional cost and complexity.

To the extent that this option is coupled with the introduction of firm capacity rights, it would improve **investment signals for the use of pipeline capacity**. See section 3.6.

In addition, with regard to **promoting upstream and downstream competition**, to the extent that this option improves market participants' ability to manage risk, it may reduce barriers to market entry and reduce market concentration.

While the Commission considers this option has merit, it would involve a complete market re-design which would be time consuming and at a potentially significant cost. For the purposes of this review, this option is not preferred compared with the short term recommendations and target model set out in the final report that the Commission considers will better meet the COAG Energy Council's vision.

3 Capacity rights

As discussed in the final report, market participants utilising the DTS cannot reserve capacity. Because market participants cannot secure firm capacity rights, they have limited incentives to underwrite capacity in the DTS, as other market participants may "free-ride" by gaining access to that capacity through the DWGM. 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 APA's DTS Access Arrangement.[41]

While users cannot hold firm capacity, they may hold AMDQ which are non-firm capacity rights and afford the holder certain limited financial and physical benefits while being consistent with the allocation of capacity dynamically through the gas commodity market.[42]

This chapter examines six options that might improve the firmness of the current non-firm capacity rights held by market participants (addressing the free-rider problem) or otherwise improve the AMDQ regime:

1. improving market signalling for AMDQ cc prior to capacity expansions
2. improved scheduling priority – where there are constraints, prioritising AMDQ holders over non-AMDQ holders where offers are under the market price
3. firmer financial rights – AMDQ holders would receive some financial compensation should they not be scheduled
4. settlement residue rights with zonal pricing – participants or other parties could obtain financial rights to transmission capacity between gas pricing zones on the DTS and receive the settlement residue that arises as a consequence of gas flowing between the zones which have different gas prices
5. firm physical entry and exit capacity rights with a net market for residual capacity allocation
6. firm physical point-to-point capacity rights.

41 AEMC, *Review of the Victorian declared wholesale gas market*, Final Report, 30 June 2017, section 2.2.

42 For more details on AMDQ, please refer to AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, stage 1 final report, 23 July 2015, Sydney, Appendix F.

Box 3.1 Key capacity rights concepts

There are a number of concepts that permeate the discussion around capacity rights and the options discussed in this chapter.

Physical rights and financial rights

Capacity rights can be physical or financial:

- physical rights: rights that provide priority or preference in the scheduling process
- financial rights: rights to receive compensation from competing shippers (who do not hold rights) if not physically dispatched, or protection from certain costs.

AMDQ provides both physical and financial rights, though to a limited extent.

Firmness of rights

Subject to AEMO and APA's reasonable endeavours and the statutory arrangements in place for curtailment, firm capacity rights holders would be guaranteed either:

- physical access to pipeline capacity (in the case of firm physical rights)[43]
- financial compensation such that they are indifferent to whether they are provided physical access (in the case of firm financial rights).[44]

Less than fully firm rights might involve some limited physical priority in scheduling or limited financial protection. AMDQ is an example of a less than fully firm right.

Importantly, firmness is not binary – depending on the design of capacity rights, the level of physical or financial firmness can vary. With regard to physical rights, the firmness can provide:

1. absolute scheduling priority: right holders' flow requirements are scheduled first, with non-rights holders scheduled to the extent that any unused pipeline capacity remains
2. relative scheduling priority: a right holder is scheduled in preference to non-right holders under certain specific conditions. For example, AMDQ provides relative scheduling priority in the form of tie-breaking rights.

---

43 A physically firm right means that the right holder is guaranteed (under normal operating conditions) to physically flow its gas.

44 A financially firm right means that a right holder may be physically constrained off, and so not physically flow its gas, but is financially compensated for this such that it is indifferent as to whether it physically flows or is compensated for not flowing.

Location of rights

Capacity rights can be defined in at least two different ways:

- Point-to-point: a point-to-point right is between an injection point and a withdrawal point.
- Entry or exit: entry capacity refers to a physical injection point to a virtual hub and exit capacity to a physical withdrawal point from a virtual hub.

Authorised MDQ is an example of a point-to-point capacity right because it relates to injections at Longford into the Longford to Melbourne pipeline. AMDQ cc is also a point-to-point right, as it is associated with a particular injection point and market participants nominate a quantity of AMDQ cc to the reference hub,[45] to specific customer sites or to a system withdrawal point at an interconnected facility.[46]

Allocation of rights

The allocation (and re-allocation) of capacity rights can be considered to be either implicitly allocated through the gas commodity market or explicitly allocated through a separate capacity market:

- Implicit allocation: there is a single market for capacity and gas, whereby capacity is allocated through bids and offers for gas submitted by market participants. The DWGM is an example of implicit capacity allocation.
- Explicit allocation: capacity is allocated separately from gas, and market participants hold physical rights. There are a number of methods by which capacity can be allocated explicitly, for example on a first come first served basis; pro-rata allocation or through an auction. Capacity can also be re-allocated through a secondary market. Entry-exit capacity allocation in the target model is an example of explicit capacity allocation.

There is also a hybrid of the two methods mentioned above: capacity is allocated through explicit long-term contracts and market participants need to nominate to use the capacity rights up to a pre-defined gate closure (such as the day before the gas day). After gate closure any uncontracted or unnominated capacity would be allocated implicitly through a net market. The option discussed in section 3.5 is an example of this hybrid approach to capacity allocation.

45 The reference hub is a notional site within the DTS established for the purpose of valuing AMDQ and AMQD cc, also referred to as the Melbourne AMDQ node. See AEMO, *AMDQ transfer algorithms*, 3 April 2012, p. 4.

46 AEMO, *Wholesale Market AMDQ procedures (Victoria)*, 25 October 2016, pp.16-17.

3.1 Market signalling for AMDQ cc prior to capacity expansions

Authorised MDQ was first allocated at market commencement in 1998 to tariff D customers (large industrial) in perpetuity on the basis of their individual historic demand. The remaining balance was then allocated as a block to tariff V customers (small commercial and residential customers). The allocation of 990TJ of authorised MDQ was (and has remained) commensurate with the original capacity of the Longford to Melbourne pipeline, and no more authorised MDQ has been (or can be) created.

Instead, expansions in the network can result in the creation of AMDQ cc. AMDQ cc are not differentiated by final customer (tariff V or D) nor exclusively allocated directly to customers, but are instead acquired by market participants (some of which are end consumers and some of which are retailers). Until recently, AMDQ cc has been allocated by AEMO to market participants for quantities and periods as indicated by APA (usually five years, reflecting the outcome for a competitive tender process APA managed).

The AMDQ cc allocation method has recently been modified.[47] The increase in pipeline capacity resulting from an expansion or extension project needs to be agreed between APA and AEMO. Once agreement is reached and the new capacity becomes operational, commensurate amounts of new AMDQ cc are created.

There are two processes by which AMDQ cc is allocated:

- Where the costs of the extension or expansion that created any AMDQ cc are included in the DTS service provider’s (APA's) opening capital base for an access arrangement period, AEMO is responsible for AMDQ cc allocation (through an auction).
- The DTS service provider (APA) is responsible for AMDQ cc allocation where the costs of the extension or expansion that created any AMDQ cc are not included in its opening capital base for an access arrangement period.

While it is possible for APA to determine the amount of prospective demand for AMDQ cc and use this to signal the need for new investment, as noted above this requires that the associated costs are not included in the regulated asset base. This may limit the extent to which this option is pursued by APA, as it will have less certainty that it will be able to recover its costs.

Any AMDQ cc not allocated by APA would be allocated via the AEMO auction. Under this approach, AMDQ cc is allocated to market participants after investment decisions regarding the creation of AMDQ cc have been made. Consequently there is a limited ability for market participants to signal, ahead of time, their willingness to purchase AMDQ cc in order to inform these investment decisions.

47 AEMC, *DWGM – AMDQ allocation*, rule determination, 24 March 2016, Sydney.

3.1.1 Description of option

This approach would seek to improve the current AMDQ cc allocation process by requiring that AEMO's allocation process be undertaken prior to pipeline capacity expansions or extensions having occurred. This would allow the demand for AMDQ cc to inform, rather than follow, investment decisions.

A number of different approaches to allocating capacity rights prior to its creation were considered for entry and exit capacity in the target model:

- open seasons, which allow parties interested in obtaining either existing or incremental capacity to request capacity during a defined window
- integrated auctions, which involve the auction of both existing capacity and varying levels of incremental capacity
- hybrid open season-integrated auctions, which use open seasons to determine whether there is sufficient demand for incremental capacity to warrant carrying out an integrated auction.[48]

The Commission preferred a hybrid open season-integrated auction for entry and exit capacity in the target model, because it would allocate capacity in an efficient, transparent and non-discriminatory manner.[49] Nevertheless, the other approaches may be more suitable to allowing market participants to signal ahead of time their willingness to pay in the case of AMDQ cc, in order to inform investment decisions.

3.1.2 Stakeholder submissions

Very few stakeholders provided comments on this option.

MEU did not support the option as it considered the current arrangement of APA and AEMO providing information to the AER was working well.[50]

AGL considered that capacity allocation should come after an expansion, not before. This is because the amount of AMDQ created is only known with certainty after an expansion is completed. However, AGL considered that if there were a clear framework on how an investment results in AMDQ, it may encourage more participants to be willing to invest. For example, an investor could obtain a certain percentage of the new AMDQ created for a certain number of years.[51]

48 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Technical Report, 30 June 2017, pp. 80-81.

49 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Final Technical Report, 30 June 2017, p. 83.

50 MEU, Submission to the assessment of alternative market designs, p. 19.

51 AGL, Submission to the assessment of alternative market designs, p. 12.

3.1.3 Assessment of option

The primary purpose of this option is to allow the market to provide stronger signals for investment in pipeline capacity. If market participants were able to commit to the purchase of AMDQ cc ahead of time, this may improve the quality of investment decisions in the DTS, because this commitment would inform the existing regulated investment decision making process undertaken by the AER and APA.

However, it is not clear that AMDQ cc are sufficiently firm enough rights to inform the regulatory investment decision making process in a meaningful manner. The value that market participants place on AMDQ cc, which would be signalled to APA and the AER through a revised AMDQ cc allocation process, is likely to be far less than the actual value of the capacity investment to the market as a whole, because of the free-rider issues.

It is therefore **not clear that this option would improve market led investment** in the DTS. APA and the AER are not able to easily use the value placed on AMDQ cc by market participants in their assessment of the total benefit of an investment compared to its costs. A largely regulatory led approach may still be required, unless firmer capacity rights are also introduced in conjunction with this option.

On the other hand, to the extent that this option improves the ability of market participants to obtain AMDQ cc, it may improve their ability to **manage congestion related risk** in the DWGM. To the extent that this option better facilitates market participants securing (non-firm) capacity rights to interconnected facilities, this option may allow for **improved trading between regions**.

In addition, enhanced transparency and certainty in the allocation process of AMDQ cc could **promote competition** and reduce barriers to entry for new market participants.

Given it is not clear that this option would improve incentives for market-led investment, and the other benefits are somewhat speculative, the Commission does not consider that this option best meets the objectives of this review.

3.2 Improved scheduling priority

3.2.1 Description of option

AMDQ currently provide market participants with limited physical scheduling priority, through tie-breaking rights and some protection against curtailment in the event of an emergency.

Under this alternative approach, the holder of capacity rights would be given improved relative scheduling priority.[52]

52 Seed Advisory, submission to the draft final report, p. 41.

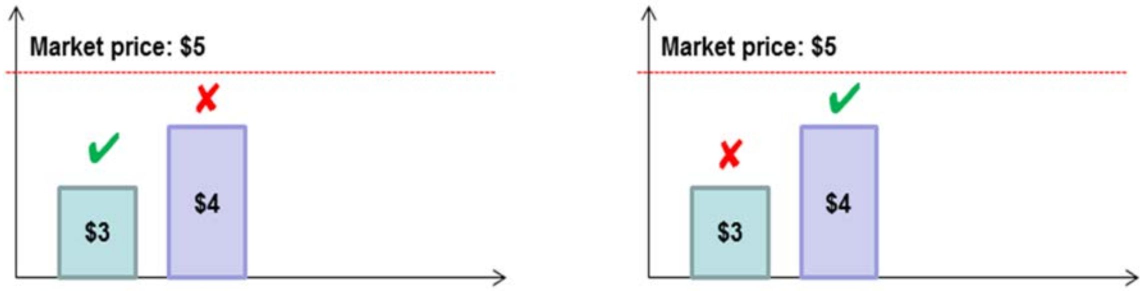
The rights holder would be scheduled in preference to non-rights holders, provided that the rights holder's offer (bid) price is less (more) than the market price.

For example, in the event of a constraint, such that two market participants' gas cannot both be scheduled, a $4 offer from a rights holder would be scheduled in preference to a $3 offer from a non-rights holder, if the market clearing price is $5. Under the current arrangements, in the event of a constraint such that two market participants' gas cannot both be scheduled, an AMDQ holder offering at $4 would not be scheduled in preference to a non-AMDQ holder offering at $3. In this way, the altered rights would be slightly firmer than current AMDQ.

Importantly, these rights would not be physically fully firm because the scheduling priority would be dependent on the market clearing price. For example, as outlined in Figure 3.1 below, in the event of a constraint such that two market participants' gas cannot both be scheduled:

- The graph on the left shows that An AMDQ holder offering at $4 would not be scheduled in preference to a non-AMDQ holder offering at $3.
- The graph on the right shows a $4 offer from a right holder would be scheduled in preference to a $3 offer from a non-right holder, if the market clearing price is $5. In this way, the altered rights would be slightly firmer than current AMDQ.

Figure 3.1 Example of improved scheduling priority



3.2.2 Stakeholder submissions

Few stakeholders provided comments on this option. However, those who provided comments did not consider it would provide substantive benefits. AEMO noted that the option would likely require a re-design of the market clearing engine, and that behaviour would not likely change as participants would still have incentives to bid at the market price floor to maximize scheduling certainty. On the other hand, AGL considered this option may incentivise participants with AMDQ to lift their offers towards the clearing price, which could result in less efficient pricing and skewed market outcomes. AGL was also concerned that participants without AMDQ would be less able to manage scheduling risk, as participants with AMDQ (but offering higher priced gas) would be preferentially scheduled.[53]

MEU did not support this option as it schedules higher priced gas in preference to lower price gas.[54]

3.2.3 Assessment of option

The primary rationale for this option is to improve the physical firmness of AMDQ, potentially addressing the free-rider problem. However, because these capacity rights would not be fully firm, market participants might not consider them to be sufficient valuable to underwrite capacity. It is therefore not clear that these rights would be firm enough to address the free-rider problem and this option is **unlikely to drive market led investment in capacity**.

Furthermore, this option is likely to deliver a marginally less efficient dispatch. Currently the DWGM market clearing algorithm used in optimising each operating schedule minimises the cost of supplying the forecast gas demand within the pipeline system security limits.[55] Inevitably, this approach moves away from this dispatch – and as a result is less efficient. Efficient and liquid allocation and re-allocation of capacity rights, for example through secondary markets, would mitigate this concern.

On the other hand, this option reduces the likelihood that participants with AMDQ will be constrained off, therefore **marginally improving the ability for participants to manage congestion related risk** in the DWGM. However, the extent to which this benefit is realised is a function of the firmness of the capacity rights. Given that the rights are only slightly firmer in this option than the status quo, this benefit may not be significant.

In addition, to the extent that this option improves the likelihood that rights holders will be able to access pipeline capacity at interconnected facilities, this option **may improve trading between regions**.

Given this option is likely to be costly to implement, and only has limited benefits with regard to marginally improving the firmness of AMDQ to support market-led investment, the Commission does not consider that this option best meets the objectives of this review.

---

53 Submissions to the assessment of alternative market designs: AEMO, Appendix B, p. 6; EnergyAustralia, p. 5; AGL, p. 13.

54 MEU, Submission to the assessment of alternative market designs, p. 22

55 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Markets*, July 2013.

3.3 Firmer financial capacity rights

3.3.1 Description of option

This option involves translating the existing AMDQ mechanism into firmer financial rights by introducing:[56]

- different tariffing arrangements for use of the DTS depending on whether the market participants hold financial capacity rights or not, and/or
- compensation paid from market participants that do not hold financial capacity rights to those that do in the event that financial capacity rights holders are constrained off.

Firmer financial capacity rights could in turn improve incentives for market-led investment.

A model for firmer financial capacity rights was developed in detail as part of the Pricing and Balancing Review undertaken by VENCorp during 2003 and 2004.[57]

Changes would be required to the current tariff structure, and could take the following format:

- capacity-based charges for capacity rights holders
- lower volumetric charges for capacity rights holders
- higher volumetric charges for non-capacity rights holders
- payments from non-capacity rights holders to capacity rights holders if capacity rights holders are constrained off.

While physical access could still be allocated through the market carriage approach, revising the tariff structure in the manner described above could address participants' requirements for financial certainty by:

- discouraging non-rights holding market participants from attempting to be scheduled due to the high volumetric payment, hence providing greater likelihood of access to rights holders
- compensating rights holding market participants in the event that a non-right holding market participant is scheduled ahead of them and they are constrained off.

---

56 Seed Advisory, submission to the draft final report, p. 41. This option was also raised in the Commission's DWGM discussion paper in September 2015.

57 Specifically Stage 2 of the Pricing and Balancing Review recommendations focused on transmission rights, see VENCorp, *Victorian Gas Market Pricing and Balancing Review – Recommendations to Government*, 30 June 2004.

3.3.2 Stakeholder submissions

Stakeholders generally considered the complexities and costs involved in implementing this option, particularly given the intra-day nature of the market, means it would be unlikely to deliver net benefits.[58]

AEMO also noted that this option appeared inconsistent with having separate pricing and operating schedules, as currently exists.[59]

3.3.3 Assessment of option

Like the other options in this chapter, improving signals and incentives for efficient investment in pipeline capacity is the central rationale for this option.

If implemented successfully, revising the tariff structure and/or introducing compensation payments might address participants' requirements for financial certainty by reducing free-rider issues currently associated with market-led investment.

Furthermore, financial capacity rights have the advantage compared to firmer physical capacity rights that the physical scheduling process is unaffected by their introduction. Of course, the bids and offers made by market participants would be expected to change compared to the status quo, influencing the scheduling outcomes.

However, setting the appropriate differential in tariffs for rights holders and non-rights holders, and/or the level of compensation paid between these two groups, is likely to be particularly important to achieving both efficient levels of investment and efficient scheduling:

- If the tariff differential or levels of compensation are too low, market participants would be unlikely to see a commercial advantage in contracting for capacity rights – in effect, the rights would not be sufficiently financially firm, and the free-rider problem would not be addressed. Capacity is only fully firm if shippers are compensated for the financial loss of not physically delivering the gas. For example, simply reimbursing the cost of capacity does not make it firm.

- If the tariff differential or levels of compensation is too high, then this might lead to incentives to over-invest in capacity and for the use of spare pipeline capacity to be prohibitively expensive.

The appropriate level of tariffs/compensation is a function of the value of capacity on the DTS. Since the value of spare pipeline capacity on the DTS would vary with short-term changes in supply and demand conditions, as well as across different locations of the DTS, the setting of the tariffs/compensation at an appropriate level is

58 Submissions to the assessment of alternative market designs: AEMO, Appendix B, pp. 5-6; EnergyAustralia, p. 5; MEU, p. 23.

59 AEMO, Submission to the assessment of alternative market designs, Appendix B, pp. 5-6.

likely to be highly problematic and **may undermine this approach's ability to support long-term market investment**.

For example, if the tariff differential and compensation were to be fixed in advance:

- at times of low congestion, the tariff differential and level of compensation may be inappropriately high, discouraging the efficient utilisation of the network
- at times of high congestion, tariff differential and level of compensation may be inappropriately low, providing insufficient firmness to the capacity rights holder.

Setting the level of compensation dynamically with regard to location and supply and demand conditions could remedy the problem. This could be achieved through either a zonal or a nodal model, which are explained in section 3.4.

With regard to risk management, this option increases the financial firmness associated with capacity rights, therefore marginally **improves the ability for participants to manage congestion related risk** in the DWGM. In addition, to the extent that this option improves the likelihood that rights holders will be able to access pipeline capacity at interconnected facilities, or be compensated if they cannot access the capacity, this option **may improve trading between regions**.

While the Commission considers the introduction of firmer capacity rights would provide better signals for investment, it considers there are significant complexities in determining the appropriate amount of compensation to achieve the benefits of this option. For this reason the Commission does not consider this option would best meet the COAG Energy Council’s vision and is not recommending it for the purposes of this review.

3.4 Zonal pricing with settlement residue rights

3.4.1 Description of option

This approach would create a number of different wholesale gas pricing zones across the DTS combined with the introduction of financial capacity rights between zones.[60]

Physical access to the DTS would still be allocated through the market carriage approach, allocating capacity on the basis of bids, offers and constraints. But, unlike the DWGM, prices in each zone would vary (as per the regions of the NEM), as a reflection of market conditions.

In theory, observed prices would be expected to:

- be equal across the zones when there are no constraints within the DTS
- diverge during times of constraint between zones.

60 Submissions to the draft final report: Seed Advisory, p. 41; Origin, p. 12. This option was also raised in the Commission's DWGM discussion paper in September 2015.

At times of wholesale gas price divergence between zones, the rights holders would be entitled to receive a proportion of the settlement residue that arises as a consequence of different prices between zones, as discussed in Box 3.2.

These payments are conceptually similar to those provided to holders of inter-regional settlement residue units in the NEM. These rights therefore would provide a means to market participants of hedging the different zonal prices associated with their injections and withdrawals.

Box 3.2 An example of inter-zonal settlement residue

In this purely illustrative example, the DTS is split into two zones, one covering Longford and the other covering Melbourne.

Demand is exclusively in Melbourne and is 100GJ.

Capacity between the zones is 50GJ.

Market participants make the following gas offers.

Table 3.1

Market participant	Offer price	Offer quantity	Location
Market participant A	$4/GJ	60 GJ	Longford zone
Market participant B	$5/GJ	50 GJ	Longford zone
Market participant C	$6/GJ	30 GJ	Melbourne zone
Market participant D	$7/GJ	30 GJ	Melbourne zone

In merit order, assuming for a moment that there are no transmission constraints, market participants A and B would be scheduled, with market participant B's offer setting the market price.

However, there is a constraint between zones, such that demand would be met through the following scheduling:

- market participant A would be dispatched for 50GJ, up to the limit of the transmission constraint
- market participant C would be dispatched for 30GJ
- market participant D would be dispatched for 20GJ.

Market participants A's offer would set the market price in the Longford zone ($4/GJ) and market participant D's offer would set the market price in the Melbourne zone ($7/GJ). Note that market participant B would not be scheduled as its offer is above the market price in its zone.

Settlement outcomes would be as follows:

- Market participant A would receive the Longford zone price for its scheduled gas: $4/GJ x 50GJ = $200
- Market participant C would receive the Melbourne zone price for its scheduled gas: $7/GJ x 30GJ = $210
- Market participant D would receive the Melbourne zone price for its scheduled gas: $7/GJ x 20GJ = $140
- Buyers in the market would pay the Melbourne zone price for all the gas: $7/GJ x 100 GJ = $700.

Consequently, the settlement revenue received from buyers exceeds the total payments made to seller by $150: ($700 - ($200 + $210 + $140)).

This inter-zonal settlement residue is equal to the price difference between the zones ($7/GJ - $4/GJ = $3/GJ) multiplied by the flow between the zones (50 GJ).

This settlement revenue would be divided between inter-zonal rights holders, in proportion to the quantity of rights they hold.

Importantly, the rights would be backed by physical network capacity, and demand from participants for additional rights would prompt the network owner to invest in additional inter-zonal capacity. Market participants could directly underwrite the creation of more capacity in return for receiving the newly created inter-zonal settlement residue rights.

As with the NEM, participation in the market and use of the system by market participants without inter-zonal financial capacity rights would be allowed, but these participants would be exposed to the divergence in prices that would result from congestion. Participants weighing these costs against the costs associated with procuring financial capacity rights would provide a market driven approach to network investment.

In order to signal the cost of congestion between zones through prices, it may be necessary for the market price within in each zone to be set using a transmission constrained schedule, as considered in section 4.1 of the final report. That is, for the price of gas to be set with regard to all transmission constraints, including both locational constraints and temporal constraints.

While market participants would be obvious buyers of the rights to inter-zonal settlement residue, as it would allow them to hedge pricing risk between zones, an alternative could be to allow any party to purchase such rights.

The appropriate number and location of zones would have to be carefully considered, with reference to both the topology of the network and the advantages and disadvantages of multiple zones, as discussed throughout the discussion of the assessment of the option in section 3.4.3. Box 3.3 towards this end of this section discusses nodal pricing, which is essentially very many zones, one at each node in the network. Box 3.4 at the very end of this section discusses optional firm access (OFA), an alternative form of firm financial transmission rights, developed by the AEMC for the NEM.

3.4.2 Stakeholder submissions

Stakeholders raised a number of positive and negative aspects of this option.

The benefits noted by stakeholders include the following:

- Prices would be more reflective of actual supply and demand in each location. Price risks can be managed through settlement rights, and the compartmentalisation of costs in each zone means participants have less exposure to costs they cannot control. Some users may have access to cheaper gas (but others more expensive).[61]
- Zonal pricing would provide more information about congestion and the locational pricing should provide better signals for investment.[62]
- Pricing signals may result in additional efficient investment in LNG capacity in the system.[63]

Stakeholder also raised the following downsides to the option:

- This option is likely to split liquidity between zones and could result in reduced competition within zones. If it proceeds, it would need to be carefully developed to ensure the liquidity in each zone was preserved to a level required for reasonable competition.[64] On the other hand, Origin did not consider having zonal pricing would negatively impact market liquidity or prevent financial derivatives when coupled with reforms to the pricing schedule. It suggested that derivatives could potentially be developed which reflect the weighted average across the market.[65]
- The rights are not fully firm so unlikely to support market led investment.[66]
- Having zones with inter-regional financial capacity rights would significantly increase market complexity.[67] It would require additional market rules to solve for constraints that may only occur on a few days each year.[68]

61 Submissions to the assessment of alternative market designs: EnergyAustralia, p. 2; Origin, pp. 6-7.

62 Submissions to the assessment of alternative market designs: ENGIE, p. 4; EnergyAustralia, p. 2; Origin, pp. 6-7.

63 EnergyAustralia, Submission to the assessment of alternative market designs, p. 2.

64 Submissions to the assessment of alternative market designs: AEMO, Appendix B, p. 7; ENGIE, p. 4; MEU, p. 23.

65 Origin, Submission to the assessment of alternative market designs, pp. 6-7.

66 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 7.

67 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 7.

As an alternative, AEMO suggested a locational constrained pricing mechanism (directional flow point constraint pricing), which would allow efficient bids and offers to be matched at the same location behind a constraint. This would enable more efficient trades to occur, despite locational constraints. AEMO considered this would be a more proportionate response than implementing full zonal or nodal pricing to achieve locational price signals.[69] This option is discussed in section 4.4 of the final report.

3.4.3 Assessment of option

The key rationale for this approach is that it provides incentives for market led investment in inter-zonal pipeline capacity. Settlement residue between zones indicates the value of inter-zonal capacity, derived from market participants' bids and offers for gas within each of the zones. These signals could be used by the AER and APA as they make investment decisions for the DTS. Alternatively, market participants could agree to underwrite capacity between zones, and in doing so acquire the financial right to settlement residue.

While this approach might represent an improvement compared to the status quo, market-led signals would only drive investment between zones and the existing process would need to be retained to govern investment decisions within zones.

The larger the number of zones (and hence the more prevalent inter-zonal capacity is), the larger the extent of market-led signals being the primary mechanism through which investment decisions would be made throughout the DTS. However, this advantage of many zones would need to be carefully trades against the various disadvantages, as noted throughout this section.

Furthermore, it is not clear that these financial rights would be fully firm, and so the value of the rights, and **the resultant strength of the market-led investment signals, may be diminished.** The quantity of inter-zonal residue is a function of the flow of gas between zones in any particular schedule. The physical nature of gas flows means that the quantity to flow between zones may not be equal to the notional capacity of the system, despite there being a price differential between zones which would otherwise drive the capacity to be fully utilised. Taking the example in Box 3.2 above, because gas does not flow instantaneously, it may be that the scheduling engine schedules less gas to flow between zones than the 50GJ of capacity notionally available (that is, a temporal constraint was the cause of the price difference between the zones, rather than a locational constraint).[70] Consequently, the quantity of settlement residue does not fully hedge a market participant's price risk between zones. This may reduce the perceived value of inter-zonal settlement rights.

With regard to risk management, this approach **introduces inter-zonal pricing risk**. For example, if a market participant injects in one zone and withdraws in another zone,

68 EnergyAusralia, Submission to the assessment of alternative market designs, p. 2.

69 AEMO, Submission to the assessment of alternative market designs, Appendix A, p. 5-6.

70 See section 2.1.3 of the final report for a discussion of temporal and locational constraints.

the market participant will be exposed to the price difference between those zones. Of course, this option also introduces a means by which this risk can be hedged, through purchasing inter-zonal settlement residue rights. That said, inter-zonal settlement residue rights may not be fully firm, and hence the market participants may not be able to fully hedge this introduced risk.

Another drawback of this approach is that having multiple zones could fragment the gas commodity market (and any associated financial derivatives market) and would split liquidity between the zones. The extent to which liquidity would be split would be a function of the number of zones created and the impact of the split liquidity on competition would depend on the market structure in each of the zones.

In addition, in a zonal pricing model there is an increased potential for market participants to possess market power within the zone, and use this power to influence market prices for the zone. This is because there are fewer potential competitors for any given market participant within each zone. It is likely that having more, smaller zones will increase the potential prevalence of market power issues and **could potentially affect competition**.

While the Commission considers the introduction of zones might provide better signals for investment, having multiple zones in inconsistent with the east coast review recommendations to introduce a single southern hub that would concentrate liquidity and provide a transparent reference price. For this reason, and the others discussed above, the Commission does not consider this option would best meet the COAG Energy Council's vision and is not recommending it for the purposes of this review.

Box 3.3 Nodal pricing

Essentially, nodal pricing is an extreme version of zonal pricing, where the market is divided up into a very large number of zones, each at an individual node on the network. As such, a price for gas at each node would be determined and settlement would be on the basis of the nodal prices.

As with both the DWGM and zonal pricing, physical capacity would be implicitly allocated through a market carriage approach on the basis of bids and offers for gas and constraints on the transmission network.

Market participants would be able to hold financial transmission rights between any two nodes, and would be entitled to the settlement residue that arises in the event that a constraint between the nodes causes prices to diverge.

While nodal pricing would in theory provide signals for market-led investment between each and every node (unlike zonal pricing, where signals for market-led investment is confined to capacity between zones), in practice, it may suffer from many of the difficulties described above with regard to zonal pricing, but to a more extreme level:

- market participants at nodes may have significant levels of market power with which they can influence nodal prices
- the liquidity of both the physical gas market and any associated financial derivatives market may be significantly split, substantially diminishing market participants' ability to manage price risk
- the actual nodal settlement residue that may result from any particular schedule may not be sufficient to allow market participants to manage price risk between nodes, because of the physical nature of gas flows.

Box 3.4 Optional firm access (OFA)

Optional firm access is an alternative financial transmission rights model developed by the AEMC for the NEM.[71] The model was not considered to further the National Electricity Objective at the time but is under regular review.[72]

Unlike the nodal pricing model described above, optional firm access only allowed for financially firm access for generators between:

71 AEMC, *Optional Firm Access, Design and Testing, Final Report - Volume 1*, 9 July 2015

72 COAG Energy Council, *Terms of reference for reporting on drivers of change that impact transmission frameworks*, 29 February 2016, available at the AEMC website.

- any individual node and the local regional reference node
- the regional reference nodes of two adjacent regions.

That is, access would not be provided between any two nodes, and instead at least one 'end' of the rights would be anchored to a regional reference node. This has a number of advantages compared to the nodal pricing described above. As a consequence of the settlement equations:[73]

- sellers could never receive a local price higher than the regional reference price, limiting their pricing influence
- settlement outcomes for both buyers and sellers were always derived based on the regional reference price, meaning that market liquidity would not be split.

While the OFA model would therefore address a number of the concerns regarding nodal (and zonal) prices in gas (namely market liquidity and market power concerns), it would still not address the fact that constraints arise in gas which are not related to the notional nameplate capacity of the system.

Under OFA, in the event of a constraint, firm capacity holders are entitled to receive the regional reference price regardless of the type of constraint, while non-firm capacity holders receive the local price regardless of the type of constraint. However, in gas markets temporal constraints (because gas does not flow instantaneously) could arise regardless of capacity expansions on the network underwritten by firm capacity holders. The negative consequences of this are:

- market participants would be incentivised to underwrite investment in capacity so as to receive the regional reference price even if that investment does not physically alleviate the temporal constraint that gave rise to the divergence between the regional reference price and the local price
- non-firm participants would be settled at the local price even though their use of the DTS was not the cause of the divergence between the regional reference price and the local price.

As a consequence of these and other complications, the Commission considers that OFA is unlikely to be an appropriate model for gas markets.

73 AEMC, *Transmission Frameworks Review*, technical report: optional firm access, 11 April 2013, Sydney, section 11.10.

3.5 Entry-exit rights with a net facilitated market for residual capacity allocation

3.5.1 Description of option

Under this option, parties would be able to secure firm entry or exit capacity rights to a virtual gas hub covering the DTS and would have scheduling priority for flows associated with these firm rights.[74]

Once firm rights holders have provided their nominations consistent with their entry and exit rights to inject and withdraw gas from the DTS, any spare entry or exit capacity to the DTS would become available for scheduling other gas flows. This spare capacity may arise because not all entry or exit capacity of the DTS is held as firm rights by market participants, or because market participants do not nominate as much gas as the capacity they hold.

This spare capacity would be allocated through a net gas market which would schedule gas based on bids and offers put forward by market participants taking into account the remaining available capacity on the DTS.

Bidding or offering gas into the net market would be voluntary, given participants may have chosen to secure firm capacity and nominate their gas prior. The net market could be used by participants for trading purposes or by AEMO to schedule gas necessary for system balancing purposes.[75]

Rights holders would need to nominate the amount of capacity they intend to use, and would be scheduled as long as the nominated amount is consistent with the quantity of rights they hold. If a rights holder wishes to flow gas in excess of their rights, the excess would need to be bid /offered through the net market, and be subject to the market clearing engine results.

This option could be coupled with an option to improve forward gas trading, so participants could more easily arrange gas supply (see section 2.3).

This option is similar to the target model in the sense that capacity rights are firm physical rights that are explicitly allocated. However, with this option a net market is retained for balancing purposes on the day and any unused capacity would be made available and implicitly allocated to market participants through their bids and offers. As with the target model, mechanisms to allow for the efficient and liquid trading of firm capacity between market participants would be required.

74 Firm physical entry and exit capacity is a feature of the target model.

75 We understand that this option was briefly considered by VENCorp during the Gas Market Pricing and Balancing Review, as part of its consultation paper covering the Pipeline Investment Issue, December 2003.

3.5.2 Stakeholder submissions

Few stakeholders provided comments on this option. However, those that did were not generally supportive.

Origin did not support this option for the same reasons it did not support the target model (that is, concerns with the development of liquidity).[76] These concerns are discussed in chapter 8 of the technical report.[77]

MEU was concerned that this option introduces significant complexity.[78]

EnergyAustralia preferred this option to the target model, however considered that further assessment should be carried out to determine whether the benefits outweigh the costs.[79]

3.5.3 Assessment of option

Primarily, this option **improves signals for efficient investment in pipeline capacity** by addressing the free-rider issue. The introduction of firm physical capacity rights should provide confidence for market participants to commit to underwrite DTS capacity, and so improve investment decision making in the DTS. Furthermore, the investment risks are shifted to market participants, rather than end consumers.

Conceivably, were a liquid secondary capacity market not to emerge, this could impact scheduling efficiency across the DTS. Some market participants which highly value capacity might not be able to acquire them, meaning that another market participant which values flowing its gas less might nevertheless be scheduled - an inefficient outcome.

If this option is combined with a forward physical market as described in section 2.3, it would provide market participants additional options and flexibility to **manage price and volume risk**. Furthermore, trading arrangements other than on the day could be unified with those at Wallumbilla and Moomba (although this is also the case through recommendation 2 in the final report). This may reduce transaction costs and barriers to entry for market participants wishing to participate in both the DWGM and at GSHs, which may **increase trading between regions**.

Trading between regions may also be increased through the additional scheduling certainty that would be provided by the introduction of fully firm entry and exit capacity rights. These are more consistent with the point-to-point contract carriage arrangements that exist outside the DTS than current arrangements, and would allow

76 Origin, Submission to the assessment of alternative market designs, p. 2.

77 AEMC, *Review of the Victorian declared wholesale gas market*, Final Technical Report, 30 June 2017, chapter 8.

78 MEU, Submission to the assessment of alternative market designs, p. 24.

79 EnergyAustralia, Submission to the assessment of alternative market designs, p. 4.

parties to enter into contracts for transport of gas from the DTS to interconnected pipelines.

The **impact on competition may be mixed**. This option gives participants flexibility as to whether capacity is obtained in advance as firm entry or exit rights, or through the net scheduling process. This may support competition as gas users can choose the arrangement that best suits their business needs. Nevertheless, access to the DTS through the net scheduling process is likely to be less available than through the existing DWGM, because some capacity (potentially a substantial majority) would already be allocated through firm entry and exit rights, and, if nominated for use by the rights holders, would not be available to other market participants.

As with the option described in section 2.3, while the Commission considers this option has merit, it would involve a complete market re-design which would be time consuming and at a potentially significant cost. For the purposes of this review, this option is not preferred compared with the short term recommendations and target model set out in the final report that the Commission considers will better meet the COAG Energy Council's vision.

3.6 Point-to-point contract carriage on the DTS

This option involves transitioning the DTS from a market carriage model, where capacity is implicitly allocated through the DWGM scheduling process, to a contract carriage model where participants can secure firm point-to-point physical capacity rights.[80]

The three sub-options raised in this paper represent the varying degrees to which point-to-point contract carriage could be introduced in the DTS:

1. point-to-point contract carriage on some constituent pipelines of the DTS while retaining market carriage for DWGM participants
2. point-to-point contract carriage on all constituent pipelines of the DTS that retains market carriage for DWGM participants
3. point-to-point contract carriage with potential balancing markets.

To avoid repetition, the description of sub-option 1 provides a relatively thorough picture of how point-to-point contract carriage could be introduced into the DTS, while sub-options 2 and 3 focus on the differences with sub-option 1.

80 The introduction of contract carriage to the DTS was raised by the Commission in the DWGM discussion paper in September 2015. A hybrid approach combining contract carriage with the DWGM was raised by APA Group: APA Group, submission to the DWGM discussion paper, pp. 28-34.

3.6.1 Description of sub-option 1

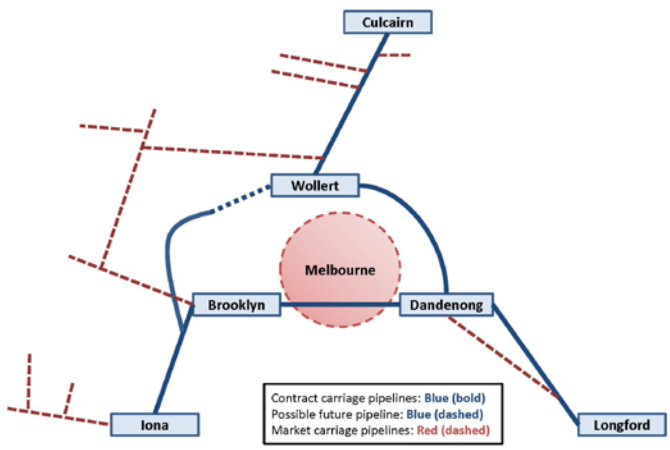
Currently, AEMO has sole access to all of the DTS capacity to operate the DWGM. AEMO is the sole 'user' of the DTS in accordance with the service envelope agreement (SEA).[81]

Under this sub-option, contract carriage would be introduced along the high capacity 'spokes' of the DTS plus the outer ring main (see Figure 3.2).[82] Shippers and (importantly) AEMO would contract with APA for gas transportation along these pipelines and APA would be the system operator for these pipelines. In this paper these pipelines are called 'CC pipelines'.

Market carriage would continue to operate for DWGM participants - on both the pipelines not subject to contract carriage[83] as well as on the portions of the contract carriage pipelines that is contracted by AEMO. AEMO would remain the market operator of the DWGM and would contract with APA for capacity on the CC pipelines to operate the DWGM.

AEMO would be the system operator for the pipelines not subject to contract carriage – it would manage the delivery of gas from the CC pipeline to the relevant exit point. This paper refers to these as 'MC pipelines'.

Figure 3.2 Point-to-point contract carriage on some constituent pipelines



Note: the proposed western outer ring main is indicated in dotted blue in this map for illustrative purposes only (on the assumption that it would be a CC pipeline in this model if constructed).

81 Section 91BE of the NGL. The service envelope agreement is an agreement between the transmission pipeline service provider (APA) and AEMO for the control, operation, safety, security and reliability of the DTS.

82 For example, contract carriage could operate on: South West Pipeline (Iona to Brooklyn); Longford to Dandenong; Culcairn to Wollert; Dandenong to West Melbourne.

83 For example, market carriage could operate on: western network; Brooklyn system; Brooklyn to Ballarat system; Brooklyn to Geelong system; Wollert to Wodonga / Echuca / Bendigo system.

Under this option, either the SEA could be amended to reflect the new terms of use of the DTS, or the framework could be changed such that the SEA is replaced with a GTA between AEMO and APA.[84]

Participants directly connected to the CC pipelines (for example gas powered generators and other large users) and participants that wish to transport gas through the DTS using only the CC pipelines would not need to participate in the DWGM. That is, these parties could 'opt out' of the DWGM and instead contract directly with APA for pipeline capacity to deliver some or all of their gas (and organise their own gas supply).

For example, a party could contract with APA to deliver gas from Longford to Culcairn to move that gas north, or deliver gas from Iona to a gas powered generator directly connected to a CC pipeline. On any given gas day the party would provide nominations to APA in accordance with its GTA and APA would be responsible for delivery in accordance with the GTA. These parties would likely be subject to a balancing regime (tolerances and over-run charges) consistent with those used for point-to-point contract carriage pipelines outside of Victoria.

The amount of capacity available on CC pipelines for market participants is discussed below.

Participants that have not 'opted out' of the DWGM (that is, gas delivered for Victorian consumption other than through the process described above or sourced from the DWGM) would be scheduled through the DWGM process. They would provide offers and bids for gas and AEMO would schedule the DWGM participants across the whole DTS (including on CC pipelines) as it does today. AEMO would then provide nominations to APA to deliver the gas, in accordance with the GTA/SEA.

Initial allocation of CC pipeline capacity

Currently, APA provides DTS capacity to AEMO and AEMO implicitly allocates capacity to participants through the DWGM scheduling process.

For the initial allocation of existing capacity, AEMO could transparently specify how much capacity it needs for DWGM purposes[85] and anything remainder would be made available to other parties.

The amount of capacity needed for DWGM purposes is likely to be less that currently required because some participants will 'opt out' of the DWGM for some or all of their capacity requirements.

---

84 In discussion with APA, it has suggested that the SEA is very input-focused, and that this leads to inefficient construction (over-building). It argues that a GTA approach is output-focused, and is more likely to drive efficiencies in investment in and operation of the DTS.

85 For example, to meet planning standards (for example enough capacity for a one in 20 year event) AEMO would need to contract with APA for capacity to each off-take point.

While there would very likely be sufficient initial capacity to meet all current requirements, the amount of 'firm' capacity available on the CC pipelines might be low compared to the total system capacity, given it may be affected by the physics of the 'meshed' network. If this were the case, we would expect a large amount of interruptible capacity to be available for use either by AEMO for the DWGM or individual participants.

Should it be necessary to allocate capacity on CC pipelines between market participants:

- a market based allocation method (such as an auction) would help to provide signals for investment in conditions of scarcity and allocate capacity to the participants that value it most
- alternatively, a pro-rated allocation method in the first instance may assist existing market participants with the transition process.

If there is more demand for capacity than is available, parties could approach APA for firm capacity on CC pipelines and signal a willingness to underwrite investment in additional capacity.

Capacity could be traded through a secondary capacity market.

Allocation of new contract carriage pipeline capacity

APA is not currently required to build pipeline capacity to meet projected demand and any investment is a commercial decision of APA. However, evidence of increasing demand may support an APA decision to invest in new pipeline infrastructure, with investment costs recovered through the access arrangement process under rule 79 of the National Gas Rules.

AEMO would contract for additional capacity on CC pipelines like any other shipper. Should AEMO's needs for the DWGM change, in addition to underwriting new investment (in turn recovering these costs from DWGM market participants), it could access CC pipeline capacity underwritten by another MP by purchasing that capacity by agreement (secondary capacity trading).

Interest in new capacity could be identified through an open season process. This would allow APA to aggregate demand on the CC pipelines and build a more efficiently sized expansion.

If there is an auction for new capacity, if the clearing price exceeds the regulated price, or the revenue exceeds the regulated revenue, excess revenue could subsidise the SEA/GTA between AEMO and APA. This would effectively pass these profits back to consumers other than those entering into a direct GTA with APA.

Managing system security

Under this sub-option there would be two system operators managing different parts of the DTS.

This would need to be managed through the GTA/SEA between AEMO and APA, which would likely need to be a complicated agreement. The GTA/SEA would set out APA's contractual obligations on the CC pipelines, such as the inlet pressures required by AEMO at each of the MC pipelines (determined by AEMO's requirements as system operator). AEMO would be able to nominate, in line with the GTA/SEA, exactly how much gas is required at each exit point to satisfy the DWGM schedule. APA would be able to use linepack in the CC pipelines to make sure it can meet its contractual obligations. This is discussed further in the assessment below.

If LNG (or other supply) needs to be injected to manage sudden supply/demand changes for the DWGM, AEMO could schedule this into the DWGM to meet changing DWGM participant demand as it currently does. In addition, AEMO could release an ad hoc schedule as necessary and send updated capacity nominations to APA – essentially the GTA/SEA with APA would need to allow for these possibilities.

Loads across the DTS could continue to be curtailed by type, without reference to whether they are DWGM loads or not. That is, the curtailment schedule would not need to change. This may require AEMO and APA to work together and coordinate curtailment of loads in accordance with load shedding tables.

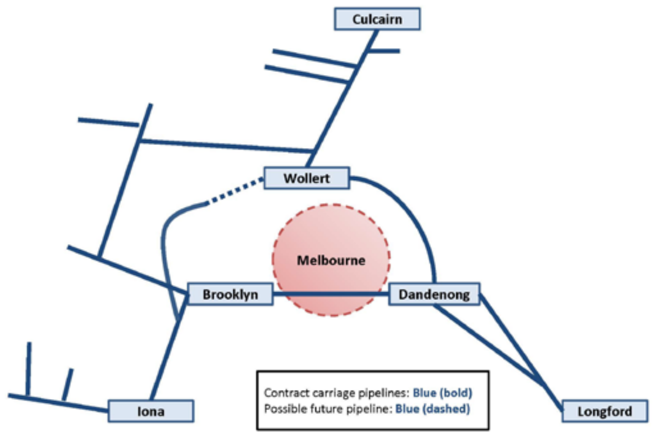
APA would also have access to risk management tools through the GTAs for the CC pipelines. APA could bilaterally negotiate for the contractual curtailment of non-essential loads.

3.6.2 Description of sub-option 2

Under this option, contract carriage would be applied to all transmission pipelines in the DTS and APA would be the system operator for the entire DTS.

AEMO would continue to operate the DWGM across the DTS and would secure pipeline capacity from APA on all pipelines to do so (as above, through the SEA or a GTA).

Figure 3.3 Point-to-point contract carriage on all constituent pipelines



Participants could choose to participate in the DWGM for the daily allocation of gas flows and capacity, or opt-out of the DWGM and arrange their own gas supply and transportation arrangements. Compared to sub-option 1, this sub-option would allow shippers anywhere in the DTS to opt-out of the DWGM. In sub-option 1, only shippers solely using CC pipelines could opt-out.

This option may also make it less complicated to manage system security compared to sub-option 1, as there would only be one system operator - APA - managing the DTS.

3.6.3 Description of sub-option 3

Contract carriage would be applied to all transmission pipelines in the DTS (see Figure 3.3 above). APA would be the system operator and AEMO may have a role in operating any balancing market that is introduced at the reference hub and/or any other demand centres. In effect, arrangements similar or identical to those outside of the DWGM/DTS in eastern Australia would be applied.

All shippers would need to contract with APA for gas transportation in the DTS and would also need to arrange gas supply.

For example, large gas users (including gas powered generators) could arrange their own GSA and GTA, or arrange a retailer to provide those services. Retailers would need to arrange GSAs and GTAs to deliver gas to all of their customers located on the transmission pipelines or on the attached distribution pipelines.

Parties would provide their capacity nominations to APA, who would be responsible for delivering the gas in accordance with the GTA.

Some form of balancing hub could be introduced at Melbourne and/or the other distribution points. For example, a physical bilateral hub similar (for example, located at Wollert or Dandenong) could be consistent with the gas supply hub design.

Alternatively, introducing market operator services[86] or an STTM-like hub would be consistent with the hubs in other major cities.

Like sub-option 2, this sub-option has only one system operator which may significantly reduce the complexities of managing the system.

3.6.4 Stakeholder submissions

Stakeholders raised a number of costs and benefits related to introducing point-to-point contract carriage in the DTS.

APA considered sub-option B would provide the most benefits. It noted that by having 'opt-in' DWGM participation, this would simply exclude some of the 'within participant trades' that currently occur in the DWGM. Retaining the DWGM would support new entrant retailers and minimise barriers to entry. APA considered that having a physical market will allow a clean forward gas price (reference price) to develop and support futures and other derivatives. The physical market could be consistent with the gas supply hub, to minimise transaction costs, with information being published on the bulletin board. APA also considered the contract carriage arrangements would support timely and efficient investment and allow participants to better manage price and volume risk (as there would be no exposure to uplift charges).[87]

On the other hand, stakeholders raised the following concerns with the option:[88]

- Having multiple system operators (sub-option 1) would lead to inefficient outcomes given the interconnectedness of the network.[89]
- There are incentives for AEMO to over-contract for capacity. For example, on a peak day, almost all of the DTS is required to meet system demand. This could result in there being little firm capacity available for other participants.[90]
- This option has lower transparency for capacity compared to the existing arrangements, particularly for price and volume discovery.[91]

86 Market operator services are essentially pipeline capacity services where shippers, through contracts with the pipeline operator, store gas if the flows to the hub are greater than demand, or supply additional gas if flows to the hub are below demand. This balances the difference between scheduled pipeline flows and what is actually consumed or delivered at the hub.

87 APA, Submission to the assessment of alternative market designs, pp. 5-10.

88 The Commission notes that some of these concerns might be able to be addressed through specific market design features.

89 Submissions to the assessment of alternative market designs: AEMO, Appendix B, p. 7; EnergyAustralia, p. 4; AGL, p. 15.

90 Submissions to the assessment of alternative market designs: AEMO, Appendix B, p. 8; EnergyAustralia, p. 4.

91 AGL, Submission to the assessment of alternative market designs, p. 15.

- There is a risk that participants could hoard capacity, which adds to costs and could reduce competition.[92]

- DWGM and non-DWGM participants would not be able to trade with each other, given the different market frameworks and contractual rights. This would reduce trading and liquidity in the wholesale market.[93]

- If retailers were able to opt-out of the DWGM, this may affect retail contestability as if a customer moves between a retailers participating and not participating in the DWGM, the allocation of capacity between retailers may be inappropriate.[94]

Origin did not support this option for the same reasons it did not support the target model (that is, concerns with the development of liquidity).[95] These concerns are discussed in chapter 8 of the technical report.[96]

3.6.5 Assessment of options

The main benefit of creating fully firm capacity rights is to **improve the incentives for market-led investment in the DTS**. The introduction of firm physical capacity rights would substantially address the free-rider issue, facilitating investment in the DTS through a market led process. Furthermore, the investment risks are shifted to market participants, rather than end consumers.

For parts of the DTS that are not transitioned to contract carriage (in sub-option 1) investment would continue to occur through the existing regulatory process. That is, there would be no change from the current arrangements.

Currently only APA can invest in transmission assets for the DWGM. This option could allow another party to invest in a lateral CC pipeline. AEMO could then buy capacity on the new pipeline for the DWGM. As such, this option allows for competition between APA and other potential pipeline owners with regard to building new assets.

Being able to access firm capacity rights will give participants certainty that they may transport gas into or out of the DTS and **improve the ability for participants to manage scheduling risk**. Shippers that utilise the contract carriage pipelines may be able to access more bespoke transportation and storage services, which may also help participants to manage risks.

In addition, the sub-options that retain the DWGM (sub-options 1 and 2) may give participants greater flexibility to choose whether they want to remain within the

92 MEU, Submission to the assessment of alternative market designs, pp. 24-25.

93 Submissions to the assessment of alternative market designs: AEMO, Appendix B, p. 7; AGL, p. 15.

94 AEMO, Submission to the assessment of alternative market designs, Appendix B, p. 7.

95 Origin, Submission to the assessment of alternative market designs, p. 2.

96 AEMC, *Review of the Victorian declared wholesale gas market*, Final Technical Report, 30 June 2017, chapter 8.

DWGM or arrange their own gas transportation and supply. This flexibility may help participants to manage risks, and **may support competition** as gas users can choose the arrangement that best suits their business needs.

Allowing participants to opt-out of the DWGM may result in less gas being traded through the DWGM. However, the type of participant most likely to opt-out may be those transporting gas through the DTS to other jurisdictions and this gas is typically offered at $0 and bid at $800 to ensure it is scheduled. That is, it is gas which is not traded between different counterparties, and it may not affect the price of gas that is actively traded between participants.

In addition, this option is more consistent with the contract carriage arrangements that exist outside the DTS and therefore may reduce transaction costs and therefore **facilitate trading between regions**.

However, this option has some potential issues:

- With sub-option 1, having two system operators is likely to cause complexities with managing the system, without providing benefits. There are often multiple flow paths that gas may take between two points. If the paths are run by different operators it will likely cause inefficiencies and pressure impacts on the other operator. In addition, it may be difficult to coordinate between system operators during emergencies unless one party is allocated overall responsibility.
- Careful consideration would need to be given to the incentives on AEMO operating in a contract carriage environment. For example, AEMO may be incentivised (through planning standards) to secure more capacity than is efficient which may result in inefficient outcomes and less firm capacity available to others. There is also no financial incentive for AEMO to make any un-used capacity available on a secondary market.
- Having point to point rights in the DTS:
  - may reduce the fungibility of gas
  - may result in there not being an efficient use of capacity (because of the meshed nature of the system).
- Splitting AEMO's market operator role from system operator may result in operational inefficiencies. For example, AEMO would run the market clearing engine in line with its contracted capacity and not with regard to the actual system conditions at the time.

While the Commission considers the introduction of firm point-to-point capacity rights would provide better signals for market led investment and facilitate trading between regions, it introduces significant operational complexities. For the purposes of this review, this option is not preferred compared with the short term recommendations and target model set out in the final report that the Commission considers will better meet the COAG Energy Council's vision.

Abbreviations

ACCC	Australia Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	authorised maximum daily quantity
AMDQ cc	AMDQ credit certificates
ASX	Australian Securities Exchange
COAG	Council of Australian Governments
Commission	See AEMC
DTS	declared transmission system
DWGM	declared wholesale gas market
GSA	gas supply agreement
GTA	gas transportation agreement
GSH	gas supply hub
LNG	liquified natural gas
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
SEA	Service Envelope Agreement
STTM	Short Term Trading Market