REVIEW

Australian Energy Market Commission

ASSESSMENT OF ALTERNATIVE MARKET DESIGNS

Review of the Victorian DWGM

30 March 2017

Submissions due 11 May 2017. Reference: GPR0002
Assessment of alternative market designs

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About the AEMC

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

Executive summary

This paper has been developed as part of the Commission's review of the Victorian declared wholesale gas market (DWGM). It is intended to facilitate further discussion of the options for gas market development in the DWGM, in particular the options that have been raised by stakeholders in recent consultation. This will inform the Commission's final recommendations for this review, which will be made in the final report to be sent to the Council of Australian Governments (COAG) Energy Council by late August 2017 and published shortly thereafter.

Issues with the current DWGM

Throughout the course of this review, and in line with the terms of reference provided by the COAG Energy Council, the Commission has identified certain design elements of the DWGM that may prevent the achievement of the COAG Energy Council's vision for a liquid east coast gas market:

- There is limited ability for DWGM market participants to effectively manage price and volume risk. There is no active financial derivatives market due to the complexity of the DWGM. Some participants instead manage risks by entering into gas supply agreements outside of the DWGM, but these are typically long-term in nature and provide limited flexibility to market participants. As gas flows become increasing dynamic and prices increasingly volatile, long term gas supply agreements appear an insufficient tool for market participants to adequately manage their risk.

- Longer term pricing signals are opaque because the DWGM is a daily market, and gas supply agreements are negotiated bilaterally (with confidential terms and prices). More transparent longer term prices can provide signals to drive the efficient use of gas in the short term, while promoting efficient levels of investment in physical gas supply and consumption in the long term.

- There is little incentive for participants to underwrite investment in the Victorian declared transmission system (DTS), as the DWGM market carriage arrangements would mean that other participants could access the capacity ('free riding'). Consequently, investment decisions in the DTS are generally the result of a regulatory process, as part of the Australian Energy Regulator's (AER's) review of the DTS Access Arrangement. Putting to one side the free-rider problem which arises from allocating capacity through the DWGM, the current regulatory approach to expansion has two substantial drawbacks compared to a market-led approach:

  - the regulator is unlikely to have the same information or incentives to make efficient decisions compared to a market participant

  - if an inefficient investment decision is made, consumers, rather than the market participant, would bear the cost of this decision

- There are currently three gas market designs across the east coast (the DWGM, short term trading market and the gas supply hub). This creates complexity, costs and inefficiencies that appear to discourage greater participation in the markets and may be preventing the efficient trading of gas between adjacent markets.

Benefits of reform

Reforming the DWGM to address the issues above is expected to be beneficial not only for Victorian gas consumers, but also for gas consumers in other east coast jurisdictions and the electricity sector.

The gas industry on the east coast of Australia has evolved into a more interconnected network with a series of increasingly dynamic markets. Improving the trading arrangements within Victoria, and between Victoria and other jurisdictions, will facilitate gas flows between these markets, allowing gas to flow to where it is most valued, including for use in gas fired electricity generators:

- Improving the ability of DWGM participants to manage price and volume risk is expected to place a downward pressure on the costs of providing and using gas.

- Streamlining the three gas market designs and moving to a more fully integrated east coast gas market will help to reduce the complexity, costs and inefficiencies that can discourage greater participation in the market.

- Establishing a reference price that better reflects the value of gas will help to provide market signals to promote the efficient use of gas and efficient levels of investment, throughout the supply chain.

- Efficient investment in the DTS will help to reduce the chance of constraints and allow participants to flow gas to where it is needed, whether that is inside Victoria or to another jurisdiction.

A more efficient Victorian gas market, in the context of an east coast gas market, is also likely to be of key importance for the electricity market, given the use of gas as a generation fuel. The increased use of gas powered generation in the electricity market, prompted by a more efficient gas market, would:

- assist with maintaining system security, as gas generators can provide stability during frequency fluctuations and system strength through contributions to fault current

- better enable the intermittent output from wind and solar generation to be balanced, thereby assisting to achieve a lower emissions generation mix compared with coal generation

- improve the availability and competitiveness of hedge contracts, assisting electricity market participants to managing their price risks

- to the extent that reforms result in more efficient gas trading, place a downward pressure on electricity prices, as gas generation may increasingly set the market price.

The Commission's draft model

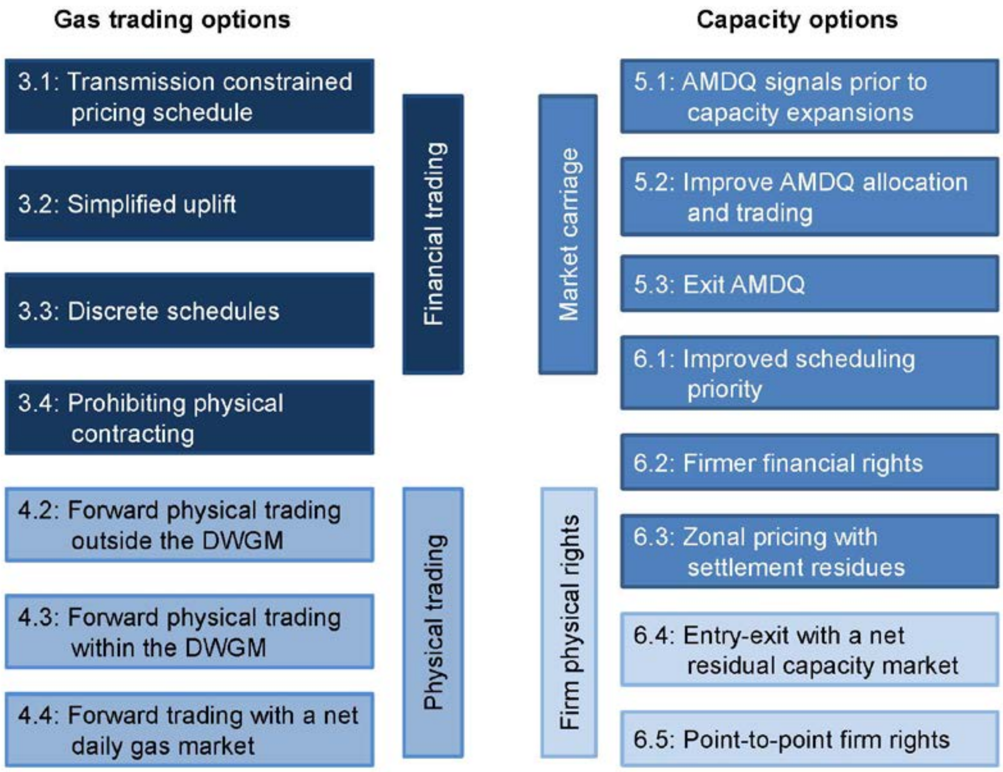
In October 2016, the Commission recommended and subsequently consulted on a draft model to reform the DWGM. The draft model would replace the daily gross pool gas trading market with bilateral or hub trading that would allow participants to continuously and voluntarily trade gas at any time. This would be coupled with changes to the implicit capacity allocation arrangements currently used within the DWGM with a system of tradable entry and exit rights on the DTS.

While there was some stakeholder support for the draft model, particularly by those with an interest in trading gas between regions, submissions by many of the existing DWGM participants supported the further examination of ‘incremental’ market reform options that would largely retain certain aspects of the DWGM. More substantial alternative reforms were also raised.

While many of the alternatives supported by stakeholders were the subject of consultation in the Commission’s September 2015 discussion paper, this consultation occurred some time ago. Re-assessing the alternatives to the draft model may uncover new benefits and other considerations that were not identified through the consultation in September 2015. The Commission welcomes this constructive stakeholder interest in determining the best solution to reform the DWGM.

Assessment of alternative market designs

This paper examines a range of options to reform the gas trading arrangements and the capacity allocation arrangements in the DWGM as set out in the figure below. These options have primarily been raised by stakeholders in the latest round of consultation on the DWGM review.



For each option, the Commission has provided a brief description of the issue(s) that the option is seeking to address, how the option could work in practice, and a first assessment of the potential benefits and issues.

These options are not likely to be successful at reducing the identified issues in the DWGM on a stand-alone basis. They would likely need to be implemented in combination with one another in order to address each of the issues identified with the current DWGM, consistent with achieving the COAG Energy Council's vision for east coast gas markets. This vision, as noted in earlier reports, can be broken into three key outcomes:

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

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

3. Market arrangements that allow participants to readily trade gas between hub locations and support a national approach to gas trading.

Consultation

The Commission welcomes feedback on the options for DWGM market reform put forward in this paper. In particular, the Commission is interested in stakeholder feedback on:

- the benefits of each option – including whether and how each option addresses the stated issues with the DWGM
- issues that may require further thought prior to implementation
- how options could be combined to best address the issues with the DWGM (some guidance is provided in chapter 8).

Submissions on this discussion paper are due by 11 May 2017.

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, which can be broken into three key outcomes:

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

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

3. Market arrangements that allow participants to readily trade gas between hub locations and support a national approach to gas trading.

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]

Concurrently, the COAG Energy Council also requested that the AEMC undertake a broader review of the design, function and roles of facilitated gas markets and gas transportation arrangements across the Australian east coast (the east coast review).[2] The final report for the east coast review was provided in May 2016.[3]

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

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

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

1.1 Background

In October 2016 the Commission made draft final recommendations with regard to the DWGM review.[4] The Commission recommended that an alternative model be introduced (the draft model) with the following key characteristics:[5]

- Introducing a continuous, voluntary trading hub over the declared transmission system (DTS). This would be similar to trading at the gas supply hubs (GSHs) at Wallumbilla and Moomba - participants could trade bilaterally or through a trading exchange. However, the draft model it would be a virtual hub (instead of the physical hub design at Wallumbilla and Moomba) meaning bids and offers would be matched regardless of the actual location of gas within the DTS.

- Allocating capacity for using the DTS through a system of entry and exit rights.

While there was some stakeholder support for the draft model, particularly by those with an interest in trading gas between regions in Australia and prospective new entrants to the DWGM, submissions by many of the existing DWGM participants called for a re-examination of alternative reforms. In particular there was support for re-examining "incremental" market reform options that would retain certain aspects of the DWGM that they consider to be beneficial to the market, while making changes to address specific issues with the DWGM. In addition, there was some support for alternative, more significant reforms to the DWGM market design to be re-considered, such the introduction of point-to-point contract carriage to the DTS, or prohibiting the physical contracting for gas outside the DWGM.

While many of these alternatives were the subject of consultation in an earlier stage of this review,[6] stakeholders have become increasingly interested in discussing (or revisiting) these and other alternatives to the draft model. The Commission welcomes this constructive stakeholder interest in determining the best most appropriate reform the DWGM.

While the Commission considers there is considerable merit in the draft model, there are benefits from re-assessing the alternatives. It allows the assessment of several new options that were not raised earlier in the review, and may uncover new benefits that were not identified through the consultation in September 2015. The Commission, and several DWGM participants, acknowledge that the level of meaningful stakeholder engagement in the DWGM review was low in 2015 due to the other market reviews underway at the time (including the ACCC east coast gas inquiry and the AEMC's east

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4 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016.

5 The draft model is explained in more detail in section 2.2.

6 AEMC, *Review of the Victorian declared wholesale gas market*, discussion paper, 10 September 2015, Sydney. The options canvassed in September 2015 included: targeted measures including targeted transmission rights, AMDQ allocation and trading, and reviewing the planning standard; firm transmission rights with a simplified pricing mechanism; zonal based pricing with capacity rights; an entry-exit model (the basis of the draft model); and a hub and spoke model (point-to-point contract carriage).

coast review). The consultation period was also relatively short considering the complexity of the options that were presented to stakeholders.

Consequently, it is appropriate to reconsider the alternatives previously assessed, as well as consider new alternatives that have been raised since September 2015.

1.2 Assessment framework

The overarching objective for this DWGM review is the national gas objective (NGO). Guiding the Commission's considerations are the COAG Energy Council's vision, complemented by the COAG Energy Council's terms of reference for this review that sets out specific desirable attributes for the DWGM.

1.2.1 The national gas objective

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

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

The NGO is structured to encourage energy market development in a way that supports the:[7]

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

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

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

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

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

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

1.2.2 The vision

Released in December 2014, the vision is as follows:[8]

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

The vision provides a high level policy statement that has guided the analysis undertaken in this review, focused on key outcomes for the gas market that are necessary to meet the NGO.

1.2.3 The terms of reference for the DWGM review

The outcomes of the COAG Energy Council's vision are broadly the subject of the Victorian Government's terms of reference for the DWGM review,[9] which is to:

> "consider whether the DWGM provides appropriate signals and incentives for investment in pipeline capacity, allows market participants to effectively manage price and volume risk, and facilitates the efficient trade of gas to and from adjacent markets. More broadly, the review is to consider whether and to what extent the DWGM continues to effectively promote competition in upstream and downstream markets, in the long-term interest of consumers."

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

- Effective risk management in the DWGM: whether market participants are able to manage price and volume risk and options to improve the effectiveness of risk management activities.

- Signals and incentives for efficient investment in and use of pipeline capacity: whether pipeline capacity is being efficiently utilised and allocated to the participants that value it most, and whether investment in the DTS will occur in an efficient and timely manner and options to strengthen the signals and incentives for efficient investment.

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

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

- Trading between the DWGM and interconnected pipelines: whether the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines, and options to allow producers and shippers to effectively operate across gas trading hubs on the east coast without incurring substantial transaction costs.
- Promoting competition in upstream and downstream markets: whether the DWGM continues to encourage the introduction of new gas supplies to the market and promote competition among retailers for the sale of gas, and the extent to which the design of the DWGM may be a deterrent to large users participating in the market.

1.3 The importance of gas market reform

1.3.1 For Victorian gas consumers

AEMO's latest Victorian gas planning report[10] identified that the supply and demand balance in Victoria will continue to tighten and that certain demand growth areas are creating locational pipeline pressure issues. While adequate gas supply is one important aspect for addressing these potential issues, it is also important that the market arrangements are flexible enough to allocate gas to the consumers who value it most, and be responsive to changing consumer needs over time.

Implementing market reforms that achieve the objectives of the DWGM review are expected to ultimately benefit consumers:

- Improving the ability for market participants to manage the price and volume risks associated with trading is expected to place a downward pressure on the costs of providing and using gas. To the extent that this reduces costs for market participants, these cost savings can be passed onto consumers.
- Establishing a reference price that better reflects the value of gas will help to provide market signals to promote the efficient use of gas and efficient levels of investment, throughout the supply chain.
- Efficient investment in the DTS will help participants to flow gas to where it is needed to meet the needs of gas consumers.
- Streamlining the three gas market designs and moving to a fully integrated east coast gas market will help to reduce the complexity and costs that can discourage greater participation in the DWGM. Reduced transaction costs may result in gas being transported between markets to where it is most valued.

10 AEMO 2017, *Victorian gas planning report: declared transmission system planning for Victoria*, March 2017.

1.3.2 For a national gas market

The reforms to the DWGM are an important piece of the wider east coast gas market reforms being undertaken by the COAG Energy Council, and the achievement of the vision.

Currently there are multiple market designs across the east coast - the gas supply hubs, short term trading market, and the Victorian DWGM. This creates complexity, costs and inefficiencies that discourage greater participation in the markets. Some participants are only registered at the hubs where they directly consume gas, which limits their ability to trade across the east coast. A fully integrated east coast gas market will provide buyers and sellers with greater opportunity to participate in any of the hubs in order to improve their commercial outcomes.

For this reason, the COAG Energy Council has agreed to reform the DWGM to create a southern hub (see box 2.2). This would help to align the trading arrangements in Victoria with those across the wider east coast to reduce transaction costs and move gas to where it is most valued. It would also seek to create a southern hub reference price to support the creation of financial risk management tools and inform investment decisions.

The benefits of these reforms to consumers in the national gas market are similar to the benefits to Victorian consumers discussed above.

1.3.3 For electricity reforms

When considering reforms to the DWGM, the Commission is also mindful of the increasingly dynamic and important linkages that exist between gas markets and electricity markets. Gas is a fuel used for electricity generation and a more efficient gas market would make it more efficient to use,[11] or invest in,[12] gas powered generation.

The increased use of gas powered generation in the NEM, at efficient prices and supported by flexible gas trading and transportation arrangements, could provide the following benefits:

- **Potentially placing a downward pressure on electricity prices:** with reduced electricity generation by coal powered plants[13] and a greater proportion of intermittent generators in the electricity mix, gas powered generation (GPG) will increasingly set the market price. Any downward pressure on gas prices resulting from more flexible and efficient trading arrangements is likely to

11 For example, a gas powered generator can manage its revenue risk through financial derivatives in the NEM. If the DWGM were improved to better support risk management of gas prices, the gas powered generator would largely be able to fix a profit margin.

12 Demand from gas powered generators may increase in response to higher NEM prices. DWGM reforms would better enable gas market participants to flexibly and quickly transport gas to regions of high demand.

13 Two coal fired power stations have closed in the last year. The Northern power station in South Australia closed in May 2016 and the Hazelwood power station in Victoria will close on 31 March 2017.

directly affect the costs for GPG and the marginal price at which they offer electricity.

- **Maintaining system security:** gas generation is synchronous, like coal and hydro-powered plants. This provides stability to the electricity network when there are frequency fluctuations, for example when supply or demand changes suddenly. It also provides system strength through contributions to fault current. The shift in the generation mix towards non-synchronous forms of generation such as wind and solar consequently gives rise to increasing challenges in maintaining the system in a secure operating state. The increased use of GPG would improve system security in the NEM.
- **Ability to balance intermittent output:** wind and solar generation is inherently variable, based on whether the resource is available. Some gas generation technologies can ramp their electricity output up or down quickly to better complement the output of renewable generation. In comparison, coal generation is typically slow to increase or decrease its output, which can result in renewable generation being 'spilled' while a coal generator ramps down, or load having to be curtailed while a coal generator ramps up.
- **Lower emission electricity generation:** gas generation is significantly less carbon intensive than coal generation. Brown coal emits approximately 1.3 tonnes of carbon dioxide per megawatt hour of electricity generated (tCO_2/MWh) and black coal emits approximately $0.9tCO_2/MWh$. In comparison, open cycle gas turbines emit approximately $0.7tCO_2/MWh$ and combined cycle gas turbines emit approximately $0.4tCO_2/MWh$. Gas is likely to be an important component in an efficient, low cost reduction of emissions for the electricity sector.
- **Contributing to the hedge contract market:** hedge contracts act as a form of insurance against fluctuating spot prices and are used to underwrite investment in new generation. With large coal plants exiting the market, there has been a decrease in the availability and competitiveness of hedge contracts. This impacts small retailers and industrial customers who are unable to manage their price risks, and can result in a less competitive industry structure, less competitive pricing, and less reliable electricity supply. Gas powered generators are able to contribute to the competitiveness and liquidity of the hedge contract market.

Having a cohesive set of reforms between the DWGM and the wider east coast will help to realise these benefits from gas generation in the electricity sector. A lower proportion of gas in the electricity generation mix as a consequence of inappropriate reform to the DWGM may make it more costly to achieve the NEM outcomes listed above, or delay the time in which they may be achieved.

1.4 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 draft 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 draft model are provided in chapter 2.

This discussion paper separates these two aspects of market design when discussing alternatives to the draft model. The Commission has noted a number of possible interrelationships and inconsistencies between options throughout the paper and specifically in chapter 8.

As such, the paper is structured as follows:

- chapter 2 provides an overview of the existing DWGM arrangements and the draft model developed by the Commission
- chapters 3 and 4 covers options to improve gas commodity market:
    - options to facilitate the development of a more liquid financial derivatives market alongside a physical spot market which retains the core features of the DWGM (chapter 3)
    - options to improve the market for forward physical trading of gas (chapter 4)
- chapters 5 and 6 covers options regarding pipeline capacity access:
    - improving the existing quasi capacity rights (authorised maximum daily quantity (AMDQ)) without increasing the firmness of these rights (chapter 5)
    - increasing the firmness of capacity rights in the market (chapter 6)
- chapter 7 lists some of the other options raised by stakeholders that may not significantly address those specific issues identified by the AEMC and the terms of reference for this review, but which might nevertheless be beneficial should the relevant aspect of the DWGM be retained.
- noting the large number of possible combinations of options, chapter 8 provides a description of several examples of possible coherent combinations of gas market and capacity allocation designs to address multiple issues with the DWGM.

This paper does not revisit the assessment of the draft model.

1.5 Consultation

The Commission welcomes responses on the options discussed in this assessment of alternatives. Any feedback received from stakeholders will be used to inform the Commission's final recommendations for the DWGM review to be presented to the COAG Energy Council and published in the final report.

Submissions on this review of alternatives are due no later than Thursday 11 May 2017.

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

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

The Commission is planning to hold several stakeholder workshops to discuss the options presented in this paper. Please see the project page on the AEMC's website for more information.

2 Background

This chapter provides background that is relevant to this assessment of alternative market designs, including:

- an overview of the current DWGM design and operation
- issues with the DWGM identified by the Commission
- the Commission's draft model for reforming the DWGM.

2.1 Operation of and issues with the existing DWGM

2.1.1 Overview of the current DWGM design

This section provides a brief description of the design features of the current DWGM, with a focus on those features which are limiting its ability to facilitate the vision. A more comprehensive description of the current DWGM can be found in stage 1 of the AEMC's wholesale gas market and pipeline frameworks review.[14]

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

- trading of gas on the gas day, including gas for balancing requirements
- managing gas flows on the DTS consistent with its physical capacity.

These points are discussed below.

Gas trading

The DWGM facilitates the trading of gas between market participants. Each market participant is required to submit price/quantity pairs of bids and offers into the DWGM in order to inject or withdraw gas from the DTS for the remainder of the gas day.[15] Based on bids and offers and subject to the pipeline system security limits, the Australian Energy Market Operator's (AEMO's) market clearing algorithm schedules each market participant's injections and withdrawals by minimising the cost of supplying demand.[16]

Market participants who are scheduled to withdraw more than they are scheduled to inject (that is, are net short) pay the market price on the quantity of gas they are short. Conversely, market participants who are scheduled to inject more than they are

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14 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, stage 1 final report, 23 July 2015, chapter 6 and appendix F.

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

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

scheduled to withdraw (that is, are net long) receive a payment of the market price on the quantity of gas they are long.[17] These payments are known as 'imbalance payments', and in effect are payments for the trade of gas between market participants.[18]

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

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

The DWGM scheduling process occurs at five pre-defined times within the gas day.[19] For the first schedule of the day, at 6.00am, gas is scheduled for the entirety of the upcoming gas day. Each subsequent scheduling process then revises the schedules for the balance of the gas day, with a new market price set for each schedule. This therefore allows for the trading of gas through the DWGM for the upcoming gas day or for the balance of the gas day.

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

These system imbalances are also managed by AEMO through the DWGM scheduling process. In such circumstances, AEMO buys or sells gas in the next schedule (at the next schedule's market price) in order to manage linepack variations in the preceding schedule, with the intention of meeting an end of day linepack target. AEMO's costs or proceeds from the trades are mostly recovered through payments made by or to market participants who deviate from their schedule, commensurate with the impact the market participants had on the system. The payments made by or to deviating parties are consequently known as deviation payments.

17 More precisely, market participants pay/receive the market price on the quantity of gas they are short/long in the first schedule; in schedules two to five, market participants pay/receive the market price on the change in the quantity of gas they are short/long compared to the previous schedule.

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

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

Deviation payments are settled at the *ex post* price (at the market price of the next schedule) because AEMO is buying or selling gas in the next scheduling horizon. This contrasts to imbalance payments, which are settled at the *ex ante* price (at the market price of the current schedule).[20]

Managing the flows of gas consistent with system capacity

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

In order for a market participant to inject gas into or withdraw gas from the DTS for the upcoming or current gas day, it is mandatory for it to offer all of its gas into the DWGM and bid to take gas out the DWGM.[21] That is, market participants must bid/offer their gross position in order to be scheduled and gain access from/to the DTS.

Market participants are required to do this as, in the event of a constraint, it provides AEMO's market clearing algorithm the information it needs to determine the lowest cost combination of gas to schedule to meet demand, subject to the constraint.[22] As such, access to the DTS is determined implicitly through the DWGM, and so the capacity arrangements are known as "market carriage".[23]

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

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

In the event that two market participants offer or bid gas at the same price but both cannot be scheduled due to a physical constraint, those holding AMDQ rights (explained in box 2.1) will be scheduled ahead of those without. In this way, AMDQ offers limited protection from the risk of being constrained off. The amount of available AMDQ rights is set with regard to the physical capacity of the system.

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

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

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

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

Box 2.1 Authorised maximum daily quantity

In the event of a constraint, market participants which are holders of authorised maximum daily quantity (AMDQ) or AMDQ credit certificates (AMDQ cc) (collectively commonly referred to as AMDQ) are provided financial rights and limited rights to physically access the DTS.[24]

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

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

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

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

- congestion uplift
- surprise uplift
- common uplift.[25]

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

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

24 A more detailed description of AMDQ and AMDQ cc is provided in chapter 5 of this paper and in: *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, Appendix F.

25 Additionally, DTS service provider (DTSSP) congestion uplift is used to recover ancillary services costs due to the DTS service provider, APA, failing to comply with its obligations under the Service Envelope Agreement (SEA).

- **Surprise uplift** charges are levied against market participants whose unexpected actions contribute to the constraint (for example by injecting or withdrawing other than their scheduled quantities, or changing their demand forecast), and hence contribute to the need for higher cost gas to be scheduled.[26] Surprise uplift cannot be hedged, but can be mitigated against through accurate forecasting by market participants.

- **Common uplift** charges are uplift charges that cannot be allocated to any market participants via congestion or surprise uplift.[27] Clearly, this risk cannot be mitigated or hedged by market participants.

2.1.2 Issues identified with the existing DWGM design

Over the course of the review, the Commission has identified the following key issues with the DWGM. A more detailed explanation of these issues may be found in section 2.4 of the draft final report.[28]

Limited risk management options

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

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

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

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

27 For example, costs associated with any inaccurate AEMO demand forecast overrides. Prior to issuing the pricing and operating schedules, AEMO prepares hourly forecasts for uncontrollable withdrawals based on weather forecasts from the Bureau of Meteorology and compares these with the aggregate demand forecasts provided by all market participants. If they differ, AEMO determines whether to override the market participants' aggregate demand forecasts. See: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, pp. 45, 86.

28 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016.

Consequently, a market participant can generally only manage its price risk in the DWGM by entering into typically long term gas supply agreements (GSAs) outside of the market and bidding this gas into and out of the market in such a way as to ensure that their scheduled injections and withdrawals match. Consequently, the market participant is in balance and so not exposed to the market price. At a time when managing risk is becoming significantly more important for market participants, this approach appears increasingly insufficient.

Opaque longer-term pricing

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

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

Limited market-driven investment in the declared transmission system

While it is currently possible for participants to underwrite investments in the DTS, this tends not to happen because of the "free-rider" problem that arises as a result of the DWGM's design. As access to the DTS is allocated on the basis of DWGM market outcomes, market participants cannot obtain exclusive access rights. The lack of such rights to use the DTS means that individual market participants have limited incentives to underwrite investments in the system. Other market participants would also benefit from a capacity expansion without having contributed to its costs, and may even be able to usurp the funding participant's ability to use it.

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

- the regulator is unlikely to have the same information or incentives to make efficient decisions compared to a market participant
- if an inefficient investment decision is made, consumers, rather than the market participant, would bear the cost of this decision.

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

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

Inhibitions on trading between markets

As discussed in section 1.3.2, there are currently three different facilitated market designs in operation in eastern Australia, with six different pricing points.[29] It is likely that the disjointed nature of these market arrangements is inhibiting trading across the east coast, increasing complexity and transaction costs. These factors may also be deterring participants in one market entering another.

2.2 Recommendations in the draft final report

As noted in box 2.2, the COAG Energy Council agreed to the broad concept of a southern hub as part of a package of recommendations on wholesale gas markets. The specific form of the southern hub would be recommended and agreed through the DWGM review process.

The Commission provided a description for a "southern hub" in the draft report published in December 2015, and a more detailed description in the draft final report published in October 2016. Throughout this paper, this is referred to as the "draft model".

29 The facilitated market designs are the DWGM in Victoria, the short term trading market (STTM) operating in Adelaide, Brisbane and Sydney and the gas supply hubs (GSHs) at Wallumbilla and Moomba.

Box 2.2 East coast review findings

The Commission's final report for the east coast review set out broad recommendations on Australia's wholesale gas markets (among other things). The recommendations related to wholesale gas markets included that:[30]

- development efforts be focussed on two primary trading hubs - a northern hub and southern hub - that share common trading arrangements to improve price discovery and reduce barriers to participation
- the northern hub be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of optional hub services
- the 'southern hub' be transitioned from the existing DWGM design to continuous, exchange based trading, supported by a system of firm capacity rights
- following these reforms, the STTM hubs be simplified to balancing mechanisms only.

While these recommendations were agreed by the COAG Energy Council in August 2016, it was acknowledged that the DWGM review was not yet completed and that "the Victorian government has requested further detailed design work be carried out so that it is in a position to better assess the recommendations".[31] The specific form of the southern hub to be recommended to the COAG Energy Council is the subject of this DWGM review.

The draft model for the southern hub recommended by the Commission would allow for the introduction of gas trading arrangements consistent with those at the northern hub by unbundling the functions currently performed by the DWGM spot market: gas trading (including balancing) and capacity allocation. The recommendations are described below, and more detailed descriptions may be found in chapters 4 to 6 of the draft final report and the accompanying technical report.[32]

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

30 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, Stage 2 final report, 23 May 2016, Sydney. Executive summary, p. 14.

31 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, Stage 2 final report, 23 May 2016, Sydney. Executive summary, p. vii.

32 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, chapters 4 to 6; AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final technical report, 21 October 2016.

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

- would be required to nominate their required flows of gas into and out of the DTS
- may voluntarily trade some or all of their gas inside the DTS, including through an exchange based on the gas supply hub design.[33] Market participants would be able to place bids or offers for any gas they wish to trade which would then be automatically matched through the exchange.

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

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

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

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

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

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

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

Market participants would be able to adjust their injections or withdrawals, or trade gas (including through the exchange), so that they would be individually closer to being in balance. Box 2.3 provides an example of how market participants would be able to stay in balance.

If, however, the system as a whole became sufficiently out of balance so as to threaten system security, AEMO would undertake a residual balancing action. The cost of residual balancing actions would be attributed to those market participants which caused the need to undertake the action.

In undertaking residual balancing action AEMO could:

- buy or sell gas on the exchange so as to increase or decrease the amount of system linepack, in the same way that it currently schedules additional gas to balance the system
- buy or sell gas to be injected or withdrawn at a specific location, in the same way that it can currently schedule out of merit order gas
- buy back capacity in certain situations to limit participants' injections or withdraws
- call for bids or offers if nothing suitable was presently available on the exchange, in order to inform market participants of possible opportunities to buy or sell gas to AEMO
- undertake these actions at any time, not only at pre-defined schedules, in a similar way that it can instigate an ad-hoc schedule currently.

Finally, AEMO's emergency directions powers would continue to be available for system security management.

As a continuous balancing regime, market participants would only be incentivised to be in balance when the system as a whole was approaching its secure limits. Linepack would be efficiently used the rest of the time, and market participants would not be required to be in balance at any particular pre-determined time (such as at the end of the gas day).

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

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

Market participants would be expected to nominate consistent with their entry and exit rights.[34]

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

Rights to existing capacity would be allocated through a variety of market and non-market mechanisms in the short and long term, on a non-discriminatory basis. Notably, exit capacity to distribution networks (primarily to serve residential demand) would be directly allocated on the basis of daily usage, and not allocated through a market.[35]

Additional capacity rights to exit capacity (other than to distribution networks) and entry capacity would be made available if market participants were willing to underwrite investment to expand the physical capacity of the system. Market participants' collective commitment to underwrite a proportion of capacity would be used as a signal by the AER to approve capacity expansions.

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

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

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

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

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

Box 2.3 An example, combining the elements of the draft model

As a virtual hub, market participants would not themselves be responsible for flowing gas across the system. To avoid being exposed to the costs of residual balancing actions, a market participant would need to remain in balance such that its cumulative injections (and purchases) equal its cumulative withdrawals (and sales).[36] It could:

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

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

The Commission investigated a number of transitional measures expected to stimulate liquidity and provide protection to market participants in adjusting to the new regime. The transitional measures should also provide a pathway to implementation of the draft model and avoid substantially diminishing the benefits of the draft model during the transition period.[37]

The transitional measures considered were:

- Non-continuous balancing: instead of (or in addition to) having continuous balancing by participants and AEMO, having a daily balancing requirement would concentrate liquidity into a balance-of-day product. Alternatively, there could be an end of day linepack target and participants that are out of balance could be charged a linepack fee.
- Physical self-supply restrictions or unbalanced obligations: participants would be restricted from obtaining all of their supply from within their own portfolios, or

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

37 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, chapter 7.

would be required to be out of balance by a certain amount. This would stimulate trading between participants.

- System operator primary balancing responsibility: participants would provide their nominations for injections and withdrawals at a cut off point. Then AEMO would be responsible for balancing the market based on a separate set of bids and offers by participants. This would allow AEMO to manage system security on the day.
- Market maker obligations: certain participants would be required to bid for and offer a certain volume of gas at a maximum price spread. This would guarantee that a certain volume of gas is made available for trade.
- System operator flexible gas: AEMO would be able to procure its own long term GSAs for system balancing purposes. This would provide certainty that gas would be available to keep the system secure.
- Tolerances: participants would not have to pay for residual balancing action if they are within certain tolerance bands. This would reduce a participants' exposure to balancing costs during the transition period and reduce the risk of having insufficient flexible gas. It may also improve incentives to offer flexible gas to the market, stimulating liquidity.

Other than the transitional measure to give the system operator primary balancing responsibility, each of these transitional measures are features added to the draft model, rather than stand-alone market designs. As this paper does not revisit the assessment of the draft model, these options are not reconsidered in this paper.

The transitional measure to give the system operator primary balancing responsibility is an alternative market design to the draft model. It is re-discussed in terms of its gas trading aspects in section 4.4 and in terms of its capacity allocation aspects in section 6.4.

3 Improving risk management options: financial derivatives market

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.[38]

As noted in chapter 2, the DWGM is a spot market (and only a spot market), meaning that market participants cannot agree a price for gas today for delivery at a future date. This limits their ability to manage the price risk arising in the DWGM.

The NEM is also a spot only market, but an active financial derivatives market has emerged as a side market to the NEM, which provides market participants (both sellers of electricity (generators) and buyers of electricity (retailers and large consumers) considerable flexibility in the way they manage risk and provides an effective alternative to physical positions.

However, a liquid financial derivatives market has not emerged as a side market to the DWGM. While the Australian Securities Exchange (ASX) has released a number of such products, no material trading in them has developed.[39]

Due to different physical characteristics of gas compared to electricity, the design of the DWGM spot market is considerably more complex than the NEM spot market. This complexity has not been conducive to the development of a financial derivatives market. In consultation with stakeholders, in the draft final report the Commission identified three particular market design features that are problematic:[40]

- uplift payments which are applied additionally to the market price, some of which cannot be hedged
- multiple pricing schedules, meaning that financial derivatives settled against the 6am price do not fully hedge any exposure to price changes throughout the gas day
- the requirement to physically inject gas in order to receive congestion uplift protection through AMDQ rights may create an incentive for market participants to take physical positions rather than financial positions in the DWGM.

38 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, pp. 21-24.

39 See the ASX website at http://www.asx.com.au/products/energy-derivatives/natural-gas.htm, accessed 19 March 2017.

40 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, p. 23.

A number of stakeholders have also suggested that the prevalence of producers entering into physical contracts with retailers and large consumers outside of the DWGM may be limiting the development of liquid financial derivatives trading.

The draft model recommended by the Commission would enable market participants to manage price risk by directly facilitating the trading of gas for physical delivery in the future through the southern hub market itself.[41]

The following options instead seek to amend the design of the DWGM to address the above market design features, with the aim of reducing the barriers to derivative trading and so enabling improved price risk management in this manner.

These options are:

- setting the market price taking into account physical constraints on the system
- simplifying uplift payments
- introducing out-of-balance intra-day schedules
- prohibiting physical contracting for gas outside of the DWGM.

A description of these four options, and their preliminary assessment, is given below.

3.1 Transmission constrained pricing schedule

Under the existing arrangements, AEMO utilises separate schedules for setting DWGM prices and for physically operating the DTS.

Pricing in the DWGM is based on an 'unconstrained' schedule, which takes no account of pipeline and pressure constraints and assumes that demand can be met by bids in merit order, irrespective of the location of injections and withdrawals across the DTS. The final bid in the merit order notionally required to meet DTS demand sets the price for the relevant scheduling interval.

Conversely, the operating schedule incorporates constraints on the quantities of gas that can be transported from one point in the system to the next.[42] Where such constraints exist, AEMO will not schedule some in merit order bids, and instead schedule some out of merit order bids as necessary to meet demand.

Ancillary payments are used to compensate the parties who provide out of merit order injections and/or withdrawals for the difference between their bid/offer price and the market price (which was derived assuming no transmission constraints).[43]

41 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, pp. 31, 35-36.

42 AEMO, *Technical Guide to the Victorian Gas Wholesale Market*, January 2010, p. 29.

43 AEMO, *Technical Guide to the Victorian Gas Wholesale Market*, January 2010, p. 63.

These ancillary payments are recovered via various forms of uplift, as noted in chapter 2.

The intention behind the existing design of uplift charges is to allocate costs in a manner that as far as practicable ensures that parties whose behaviour contributes to costs being incurred pay for the costs their behaviour causes, so as to encourage efficient decision-making by participants (and the DTS service provider, in the case of the DTSSP congestion uplift).

However, the risk of market participants incurring uplift charges means that any derivatives settled against the DWGM spot price (the market price) do not necessarily provide a good hedge for buyers’ wholesale purchase costs. The existence of such unhedgeable costs means that uptake of successful financial derivative products for the DWGM may have been hindered.

3.1.1 Description of the option

A number of stakeholders supported the consideration of a move to single operating and pricing schedule where the market price is set taking transmission constraints into account (a "transmission constrained pricing schedule").[44, 45]

Using a transmission constrained pricing schedule, there would be no need for AEMO to make ancillary payments to market participants scheduled out of merit order because constrained on market participants' offers would be equal to, or less than, the market price.[46] All market participants would be settled on the resulting transmission constrained schedule price, as broadly occurs in the NEM.[47] Consequently, there would no longer be any need for AEMO to impose uplift charges on market participants to recover ancillary payments.

AMDQ would not be needed to financially hedge congestion uplift, but it could continue to provide physical tie-breaking rights as between injection and withdrawal bids made at identical prices.

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44 Seed Advisory, submission to the draft final report, 2 December 2016, p. 40. This option was also raised in the Commission's DWGM discussion paper in September 2015.

45 Using a transmission constrained pricing schedule, the price will be the same or *higher* than an pricing schedule which does not take into account transmission constraints.

46 An exception to this could be made in the case of constraints arising as a result of the DTS service provider (APA) failing to comply with its obligations under the SEA. In this case, ancillary payments could be made to constrained on market participants by APA (that is, retain the existing DTSSP uplift charges). The market price would be set taking into account the constraints that would have existed had APA complied with the SEA.

47 In the NEM, the regional reference price reflects the marginal value of electricity at a specific location – the regional reference node – and static loss factors are used to adjust settlement payments to and from market participants by their location within the region; whereas under the simplest form of transmission constrained schedule pricing, the DWGM price would be set by the highest scheduled offer anywhere across the DTS.

The primary rationale for moving to transmission constrained pricing schedule is to simplify and increase the transparency of market prices. The ‘cleaner’ market price that results could increase the utility of derivative contracts settled against the spot price, potentially leading to the emergence of a liquid financial derivatives market.

3.1.2 Assessment of option

Moving to a transmission constrained pricing schedule would represent a major change to the design philosophy of the DWGM. The current imperative to identify "causers" of costs and levy various classes of charges on the relevant causers would disappear and prices would be set as they are in most commodity markets – reflecting the open interaction of the forces of demand and supply. While this would represent a major change to the design of the DWGM, it would require fewer changes than the redesign inherent in the draft model and in a number of other options discussed later in this report.

Higher and more volatile prices

Adopting a transmission constrained pricing schedule could be expected to lead to higher and more volatile DWGM price outcomes than at present. Under the current arrangements, only gas scheduled out of merit order effectively receives its offer price; gas scheduled within merit order is paid the (lower) unconstrained price. Using a transmission constrained pricing schedule, the market price for all settlement would reflect the value of the marginal offer required to meet demand anywhere on the DTS. Effectively, all sellers would receive the price that only sellers scheduled out of merit order presently receive. This would result in a wealth transfer from buyers of gas in the DWGM to sellers of gas, which we would expect would ultimately be passed to consumers.[48] The economic consequences, and hence the long-term interests of consumers of this wealth transfer, are discussed below.

The extent of this wealth transfer could be reduced if combined with a reduction in the market price cap and/or the cumulative price threshold to mitigate or offset any increase in the market price. Empirical analysis of historic ancillary payments may be able to inform the extent to which this wealth transfer would be material enough to warrant considering this approach.

The likely increased volatility of spot prices under a transmission constrained pricing schedule would create large risks for users and potentially discourage participants from "buying off the spot market". While buyers without GSAs may become less willing to purchase gas unhedged from the DWGM, the availability and liquidity of financial derivatives to enable participants to hedge spot purchases might improve (indeed, this is the core rationale for the option), albeit at prices reflecting higher average prices and volatility. Clearly, were a liquid financial market not to emerge despite this change, risks for market participants might increase without a commensurate improvement in the ability for market participants to manage those risks.

48 Submissions to the September 2015 discussion paper: AEMO, p. 6; ERM Power, p. 4; GDF Suez, p. 3.

Gaming behaviour

There is a potential concern that LNG holders could withhold cheaper injections from, say, Longford, in order to create constraints and require high-priced LNG to be scheduled, thereby raising prices to the entire market.

While physical withholding at Longford (say) by those that also hold gas at Dandenong may be attractive for market participants under a transmission constrained pricing schedule, economic withholding could be just as attractive for market participants who are under the existing unconstrained pricing arrangements. Market participants with market power and gas at both Longford (say) and Dandenong LNG could raise their bid prices at Longford to just below bids at Dandenong LNG in order to increase the (unconstrained) market price to (just below) the Dandenong LNG price while avoiding the need for AEMO to schedule gas out of merit order. Consequently, it is not clear that a move to constrained pricing would materially increase the exercise of market power by larger market participants. The Commission welcomes feedback in this regard.

Cost-to-cause and economic efficiency

Another concern about moving to a transmission constrained pricing schedule is that it would result in all buyers of gas across the DTS paying a higher price rather than just those participants who 'caused' the need for higher-priced gas to be scheduled, thereby diluting incentives on participants to:

- signal efficient investment in the DWGM, via holding AMDQ to avoid congestion uplift
- forecast their gas requirements accurately (to avoid surprise uplift) so that AEMO is not required to schedule more expensive gas later in the gas day to make up for having not scheduled cheaper gas earlier in the day.

Setting aside concerns that the cost-to-cause mechanism may currently be inaccurate in some circumstances (see box 3.1), it is not clear that seeking to impose uplift costs on their putative 'causers' best promotes the NGO.

Firstly, removing uplift charges may have little impact on the incentives on market participants to avoid behaving in ways that requires more costly gas to be scheduled by the system operator:

- With regard to removing congestion uplift, AMDQ does not provide firm capacity rights and so market participants currently have weak incentives to undertake market-led investment. Diluting the benefits of AMDQ by making the protection against congestion uplift redundant is not likely to affect the quality of investment decision making in the DTS, which would continue to be undertaken primarily through the existing regulatory-led process.

- With regard to removing surprise uplift, market participants would continue to face incentives to accurately forecast their gas requirements through (higher) deviation payments. In the event that deviations caused more expensive gas to be scheduled out of merit order in the subsequent schedule, deviation payments would, under a transmission constrained pricing schedule, be settled at a (higher) market price. Incentives to forecast accurately remain and so instances of more expensive gas being scheduled because of inaccurate forecasts may not increase. Consequently, it is not clear that productive efficiency is reduced through removing surprise uplift.

Secondly, a transmission constrained pricing schedule may be more allocatively efficient compared to the cost-to-cause approach as envisaged through the DWGM. Under the current arrangements, only those participants whose demands have risen, or supply fallen unexpectedly since the last schedule, face incentives via uplift charges to curb their offtakes or increase their injections back to those originally envisaged. However, there may be other participants with more predictable demands who nevertheless value gas less. These other participants may be able to curb their offtakes or raise their injections at lower cost (assuming they were providing with sufficient information about the ongoing supply and demand for gas within a schedule to make any adjustments) if they are exposed to the price signals.

Effective risk management in the DWGM

As noted above, eliminating uplift charges by moving to a transmission constrained pricing schedule would make the DWGM spot price a better indicator of buyers' wholesale gas purchase costs than the spot price as presently determined. This should increase the usefulness of financial derivative contracts settled against the spot price for hedging retailers' and large consumers' spot exposures.

Participants injecting gas into the DWGM may also be more willing to offer derivative contracts, as contract prices would rise to reflect higher expected spot prices and increased spot price volatility.

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

AMDQ currently provides holders protection against congestion uplift. Removing congestion uplift would make this protection redundant and so necessarily diminish the value of AMDQ.

However, as noted above, AMDQ does not appear to currently provide strong signals for market-led investment. While further reducing the benefits of AMDQ would theoretically further entrench the free-rider problem that currently exists for market-led investment in the DTS, in practice this impact may be minimal. Signals for investment may therefore be unchanged compared to the status quo.

Trading between the DWGM and interconnected pipelines

This approach does not appear to be significantly impact trading between the DWGM and interconnected pipelines compared to the status quo.

Competition in upstream and downstream markets

To the extent that this option improves market participants' ability to manage risk, this option may reduce barriers to market entry, reducing market concentration and so promote competition in upstream and downstream markets.

3.2 Simplified uplift payments

An alternative means of removing or reducing the negative effect of uplift payments on derivatives trading would be to retain ancillary payments but dramatically simplify the way in which they are recovered through uplift charges.[49]

3.2.1 Description of the option

Under this approach, congestion and surprise uplift would cease to exist and the associated costs would instead be recovered through common uplift, effectively smearing the cost across all market participants.[50] If the smearing was done on the basis of gas volumes, then all market participants would receive the same overall price for a unit of gas, comprised of:

- the (current) market price on a dollar per unit basis, as derived assuming no physical constraints on the DTS, plus
- a common uplift charge, also on a dollar per unit basis.

In effect, the cost of ancillary payments would be internalised into a single, overall per unit price both paid to sellers and charged to buyers.[51] Market participants could use this overall price to hedge risk through derivative contracts and would not be exposed to the risk that currently occurs due to congestion and surprise uplift.

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49 This option was raised in submissions to the draft final report: Seed Advisory, p. 40; Origin, p. 11.

50 The rationale for removing congestion and surprise uplift does not appear to hold for the DTS Service Provider (DTSSP) uplift charge levied against APA. As such, this uplift could be retained and paid to market participants constrained on as a result of APA failing to meet the requirements set out in the SEA.

51 This overall per unit price might come to be known as the "market price", despite being derived differently from the current market price. Furthermore, the name "uplift" also becomes somewhat redundant. Although fulfilling the same role as uplift charges currently do (covering the cost of ancillary payments) the charge would not be an uplift additional to the newly defined market price but internalised within the overall per unit price.

This may make derivatives more valuable and useful risk management tools, improving liquidity in the derivatives market and enabling market participants to better manage spot market risk.

3.2.2 Assessment of the option

This option shares a number of similarities with the option to remove ancillary payments, as discussed in section 3.1 above.

Prices not expected to be significantly higher or more volatile

In comparison to a transmission constrained pricing schedule option discussed in section 3.1 above, this option would not entail a wealth transfer from buyers (including end consumers) to sellers of gas. This is because in this option participants pay a transmission unconstrained market price and uplift costs would be smeared across all buyers. In comparison, with a transmission constrained price, all buyers would be paying the marginal cost of gas. Consequently, overall wholesale prices would not be expected to be more volatile compared to prices under a transmission constrained pricing schedule.

The total costs on the market therefore would not be expected to increase significantly[52] as a result of this reform, as market participants would collectively still be paying the (currently defined) market price plus ancillary payments. However, individual market participants might be expected to pay more or less than currently, because of the way that ancillary payments would be socialised rather than targeted to market participants.

Cost-to-cause and economic efficiency

The discussion in section 3.1 noted that in using a transmission constrained pricing schedule, market participants would be exposed to the marginal cost of gas on any deviations to their schedule. They may therefore continue to have incentives to forecast their gas requirements accurately and hence not to deviate where doing so would cause the marginal cost of gas to be high, despite removing surprise uplift charges.

Under this approach, market participants would not be exposed to the marginal cost of gas on any deviation. Instead, a deviating market participant would only incur the market price (set as currently, using a transmission unconstrained pricing schedule) plus a fraction of the ancillary payment otherwise smeared across all market participants. As such, they may have limited incentives to accurately forecast their gas requirements, resulting in an increased prevalence of more costly gas having to be scheduled to meet unexpected changes. Productive efficiency may therefore decline and prices rise.

52 There may be a decrease in productive efficiency which causes prices to rise slightly. See the discussion on cost-to-cause and economic efficiency.

As noted in section 3.1, a consequence of the current unconstrained transmission price scheduling is that not all market participants share the same incentive to alter their behaviour in response to changing supply and demand conditions. This may be allocatively inefficient, as market participants which may be able to adjust their demand or supply at lower cost than those exposed to uplift charges are not incentivised to do so.

Under this approach, market participants would all share the same incentive to alter their supply and demand in light of unexpected changes (providing market participants all have sufficient information regarding unexpected changes). This might increase allocative efficiency compared to the status quo.

Box 3.1 More cost reflective uplift charges

A number of stakeholders[53] suggested that although the intent of the current market design is for ancillary payments to be recovered in a cost reflective manner through congestion and surprise uplift charges, the cost-reflectivity of these charges is not strong in all circumstances. As such, stakeholders have suggested that *more* cost reflective uplift charges may be warranted - in direct contrast to the option being discussed in this section, which involves simplified, less cost reflective uplift charges.

For example, on 1 October 2016, the Longford facility suffered an outage and was unable to meet production targets, resulting in the need for AEMO to inject out of merit order gas from Dandenong LNG.[54] These circumstances appear consistent with a surprise-type event, meaning that those parties who were unable to inject should have borne the cost of the ancillary payments. However, we understand that the parties who paid the majority of the uplift were those who had insufficient AMDQ including those parties not operating at Longford and who therefore could not have been said to have caused the shortfall in the conventional sense.

A more cost reflective uplift charge methodology is likely to be more complex, and in any event will not internalise the cost of congestion into a "clean" market price. As such, it is unlikely to be consistent with improving the use of financial derivatives to manage risk.

We understand that AEMO is currently working with market participants to consider whether the allocation of uplift charges during ad hoc schedules should be reviewed.[55] Given that more cost reflective uplift charges do not appear consistent with improving market participants' ability to manage risk through an improved financial derivatives market, the AEMC does not intend to further analyse this approach. Nevertheless, more cost reflective uplift charging may be beneficial, for example if other options to manage risk (as discussed in this paper) are pursued.

53 Seed Advisory, submission to the draft final report, 2 December 2016, p. 40.

54 AEMO, *DWGM Event - Intervention - 1 October 2016*, 14 October 2016.

55 AEMO, Gas wholesale consultative forum draft minutes, 12 December 2016.

Effective risk management in the DWGM

As with implementing a transmission constrained pricing schedule, a key benefit of simplifying uplift is to potentially improve the conditions for the development of a liquid financial derivatives market, and hence increase market participants' ability to effectively manage risk in the DWGM. The new "market price" (inclusive of socialised uplift charges) would be a "cleaner" price on which financial derivatives could be settled and which would more fully hedge market participants' total wholesale cost of gas.

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

As with the option discussed in section 3.1, this approach would appear to reduce the benefits of holding AMDQ. To the extent that AMDQ enables market-led investment in the DWGM, this may negatively impact investment decisions. However, as discussed above, given that the majority of investment decisions are currently made through a regulatory approach because AMDQ is not a sufficiently firm capacity right, it seems likely that investment decisions will not be materially worsened under this approach.

Trading between the DWGM and interconnected pipelines

This approach does not appear to significantly impact trading between the DWGM and interconnected pipelines compared to the status quo.

Competition in upstream and downstream markets

As with the other options in this chapter, to the extent that this option improves market participants' ability to manage risk, this option may reduce barriers to market entry, reducing market concentration and so promote competition in upstream and downstream markets.

3.3 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.[56] The introduction of the multiple pricing schedules was to allow for more granular pricing and scheduling.

However, throughout this review, stakeholders have identified that balance-of-day schedules may be inhibiting the uptake of trade in financial derivatives.[57] In particular:

- 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.

3.3.1 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, within each day, "buy"/"sell" gas from/to the market and store it in 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 AEMO's "transactions" are taken into account.

For example, during overnight schedules, when demand is typically at its lowest (and so prices low), AEMO would buy additional gas from the market and increase linepack, ready to sell it back to the market in the afternoon schedules when demand is highest (and so prices high).

56 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.

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

While AEMO would buy and sell the same quantity of gas throughout the day in order the return the system to being in balance over the day, the price at which it buys/sells gas is likely to change. All else equal, we would expect it to buy at a low price (when demand is low) and sell at a high price (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, nighttime) and times of higher demand (for example, daytime, particularly the evening peak).

AEMO’s demand for gas overnight will increase the market price. Similarly, AEMO’s supply of gas 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 existing 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 "buy"/"sell" gas in a subsequent schedule to balance any deviations from scheduled injections/withdrawals and actual injections/withdrawals in the previous period, and pass these costs/revenues through to 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 nighttime 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 every five years (as AMDQ cc are now).

This approach has strong parallels to the current allocation of transportation capacity through the DWGM and quasi 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.

If this is implemented in conjunction with moving to a transmission constrained pricing schedule (see section 3.1) or removing uplift charges while retaining ancillary payments (see section 3.2), it would retain a “surprise regime” (albeit one that looks very different to the one we have currently). If a market participant failed to anticipate high future demand and failed to purchase enough linepack, it may be exposed to imbalance payments settled at a high market price. A market participant which anticipated high demand and bought linepack would be able sell it when prices were high, offsetting its exposure to those high prices.

3.3.2 Assessment of the option

Were AEMO to "buy"/"sell" linepack itself (that is, under the first, less sophisticated version of this option), a key consideration would be how AEMO would determine the appropriate end of schedule linepack target, and hence how much gas to buy or sell. 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. Were market participants 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.

Even if there was a market for linepack (that is, under the second, more sophisticated version of this option), AEMO would need to determine how much linepack to make available to 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.

Effective risk management in the DWGM

As with all the options in this chapter, a key benefit of this approach could be improving the usefulness of financial derivative products. In turn, this might increase their liquidity, and so enable market participants to more effectively manage their risk.

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 sufficient derivative contracts. As with currently, any forecasting error in this regard would lead to exposure to the market price.

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.

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

This approach does not appear to significantly improve signals for pipeline investment in the DTS.

Trading between the DWGM and interconnected pipelines

This approach does not appear to significantly impact trading between the DWGM and interconnected pipelines compared to the status quo.

Competition in upstream and downstream markets

As with the other options in this chapter, to the extent that this option improves market participants' ability to manage risk, this option may reduce barriers to market entry, reducing market concentration and so promote competition in upstream and downstream markets.

3.4 Prohibiting physical contracting for gas outside of 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.

Electricity retailers normally charge customers an electricity price that shields customers from direct exposure to spot price volatility in the wholesale market. Retailers must manage the risk of a highly volatile spot price, while supplying their customers with a more-or-less fixed price. Spot price volatility also creates risks for generators. Generation investment involves large fixed costs, and significant ongoing operating and maintenance costs. However generators do not have any certainty as to the spot market revenue they will receive from operating.

Generators and retailers seek to manage these risks by entering into a range of financial relationships with each other and with other financial market participants. Given the opposing payoffs to retailers and generators from high and low spot prices, there is a mutually beneficial opportunity for both types of participants to enter into financial relationships that allow them to better manage their risks. Generators and retailers seek to manage their exposure to the spot price by trading financial derivatives.[58]

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 DWGM and can manage their risk through long-term physical contracts there are no

58 Some market participants also manage their spot exposure by becoming vertically integrated (operating both generation and retailing businesses). To the extent its generation and retailing exposures to the wholesale market match, a market participant has a "natural hedge" against movements in the spot price of electricity.

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.

3.4.1 Overview of the option

Under this option, producers and their counterparties would be prohibited from entering into physical contracts outside 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.

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 by restricting the physical gas market, this may stimulate a liquid financial derivatives market, allowing market participants to better manage risk than currently.

3.4.2 Assessment of the option

The geographic extent of the prohibition on physical trading outside of the DWGM will be 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[59], which were accepted by the COAG Energy Council[60] and are currently being progressed by the Gas Market Reform Group[61]

- 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.[62]

The Commission is therefore not considering the national implementation of this option. Instead, it welcomes feedback on the potential benefits and challenges of implementing this option in Victoria only.

There are a number of approaches to the geographic extent of this option:

- 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.

These approaches may have significant transitional and legal challenges. However regardless of where the "boundary" is set, this model still allows for bilateral trading on the interconnected network outside of the boundary, be that within Victoria but away from the DTS, or outside of Victoria. The Commission has concerns regarding inconsistent treatment of producers in this fashion, including:

- possible perverse incentives to produce/consume inside/outside of Victoria/DTS

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

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

61 See: gmrg.coagenergycouncil.gov.au.

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

- diminished benefits of the proposed model (liquidity in the derivatives market may be hindered if some physical trading is still possible).

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.

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.

Effective risk management in the DWGM

The main rationale for this model is that by prohibiting physical trading of gas outside of 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.

On the other hand, some stakeholders have suggested that requiring producers to participate in the DWGM may encourage them to provide more flexibility to existing market participants.

Signals and incentives for efficient investment in and 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.

Competition in upstream and downstream markets

Stakeholders have suggest 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.

Trading between the DWGM and interconnected pipelines

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.

4 Improving risk management options: forward physical trading

Chapter 3 described options to address barriers to derivative trading in the existing DWGM. An alternative (or complementary) set of options to improving risk management is to enhance the ability of market participants to take physical forward trading positions to manage their price risk.

Many market participants already enter into physical forward trading positions by entering into GSAs outside of the DWGM, for example with producers at injection points to the DTS.[63,64] Approximately 80 per cent of trading takes place outside of the DWGM in this way, and has led to most participants aligning their bids and offers in the DWGM to the terms of their GSAs.

However, as noted throughout this review, GSAs appear increasingly insufficient as a tool for market participants to manage their exposures to the DWGM market price. GSAs that are now being offered by producers tend to have more restrictive and more expensive load factor flexibility than historically (that is, market participants are less able to vary the quantity of gas they receive) at a time when increased flexibility to manage price volatility is required.[65]

The physical forward trading of gas within the DWGM is not currently possible because it is inconsistent with the way capacity is allocated through the DWGM. As gas and capacity are allocated simultaneously through the DWGM, the forward physical trading of gas is inconsistent with the daily and intra-day allocation of capacity.

The draft model recommended by the Commission would allocate capacity through a market separate to the commodity market. This would overcome the difficulty in the current market design of forward physical trading of gas while capacity is allocated on a daily and intra-day basis. This would allow for the trade of gas for physical delivery in the future through the facilitated market itself.[66] In effect, access to the DTS would be contract carriage (but with capacity allocated on an entry and exit basis, rather than point-to-point basis as typically occurs outside of Victoria) and trade of gas facilitated in much the same way as at the GSHs at Wallumbilla and Moomba.

However, a number of market participants have raised some concerns with the draft model, suggesting that unlike the DWGM (which is a gross market with market carriage pipeline capacity allocation):

63 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, pp. 21-22.

64 Market participants can also naturally hedge by becoming vertically integrated (that is, producing and supplying their own gas to meet their portfolio of demand).

65 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, p. 22.

66 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, pp. 31, 35-36.

- having to participate in a separate capacity market would increase complexity, introduce a risk of purchasing capacity without commodity (or vice versa) and increase barriers to entry
- the proposed voluntary and net gas trading market may have low liquidity and hence high prices, particularly for purchasing gas for delivery that day, when market participants would face financial incentives to remain reasonably in balance
- AEMO would only have residual rather than primary responsibility for balancing during the day, which, without sufficient tools, may be problematic for the security of the system.

4.1 Summary of options

The options described in this chapter allow for the retention of some or all of the features of the DWGM that may be beneficial while still seeking to enable forward physical trading of gas to improve market participants' ability to manage risk. These options are:

- improved trading of gas outside of the existing DWGM, while retaining the core design features of the existing DWGM
- enabling the trading of gas at the DTS for delivery in the future, and integrating outstanding trade positions into the existing DWGM spot market
- the introduction of a voluntary net market (as per the draft model) but with AEMO retaining full responsibility for balancing on the day.

The key differentiating features of these options (and the existing DWGM and draft model) are outlined in the table below.

Table 4.1 Summary of options to improve forward trading

Option	Gas trading		Balancing responsibility	Readily compatible with market carriage
	Before the gas day	On the gas day		
Existing DWGM	Primarily long term GSAs outside of the DTS, with limited bespoke and opaque bilateral trading	Gross pool	AEMO, by "trading" gas with market participants	Yes
Improved trading of gas outside of the existing DWGM	Shorter term, lower transaction cost trades outside of the DTS	Gross pool (as per DWGM)	AEMO, by "trading" gas with market participants	Yes
Integrate forward trading into the existing DWGM	Trades integrated into the facilitated market	Gross pool (as per DWGM), with adjusted settlement outcomes	AEMO, by "trading" gas with market participants	Yes
AEMO primary balancing responsibility in a voluntary net pool	Trades integrated into the facilitated market	Net pool	Balancing exclusively undertaken through "trades" with AEMO (that is, no ability for market participants to adjust their injections or withdrawals)	No
Draft model	Trades integrated into the facilitated market	Net pool	Market participants by trading with one another or adjusting their injections or withdrawals, with AEMO being a residual balancer	No

The remainder of this chapter explains the three alternative options in detail, with particular regard to the features outlined in the table above.

4.2 Improved trading of gas outside of the existing DWGM

As noted above, many market participants currently enter into long-term physical contracts (GSAs) outside of the DWGM to manage price risk in the DWGM.

The Commission understands that while a limited number of bilateral secondary trades of physical gas between market participants do occur, they are typically bespoke, reflecting the needs of the counterparties to the trade. Furthermore, there is no facilitated market through which counterparties can quickly find one another to execute bilateral trades. Additionally, the price and other terms and conditions of any bilateral trades are not published, meaning that counterparties have limited information of relevant past trades in the market on which to based future trading decisions.

As a result, the Commission understands that the majority of bilateral trades outside of the DWGM are relatively long-term in nature, reflecting the high search and transaction costs to execute trades. For example, not being able to find a prospective counterparty prior to the time of the prospective gas trade taking effect limits the likelihood of otherwise efficient short-term trades taking place. Similarly, having to negotiate terms and conditions (or understand terms and conditions on offer) is likely to limit short-term forward physical trading, both because the transaction cost is disproportionately high in comparison to the value of the gas being traded and because of the time taken to execute the trade.

The Commission also understands that the DWGM process whereby gas produced or injected into the DTS at a single source (for example, Longford) is allocated between market participants is cumbersome, imposing indirect costs on market participants. This may be further diminishing the value and likelihood of otherwise efficient trades. This is likely to have a disproportionate effect on those trades where the value of gas being traded is low - particularly short-term trades and those required by small market participants.

Consequently, the flexibility to manage risk through shorter-term physical trades or to trade small amounts of gas outside of the DWGM may have been hindered.

4.2.1 Description of the option

Under this option, a variety of measures to reduce transaction costs and improve particularly the liquidity of shorter-term or low value physical trades outside of the DTS would be introduced.[67]

Measures which might be relatively low cost to implement include:

- the introduction of non-compulsory standardised shorter-term gas contracts in order to reduce transaction costs
- improvements to the process by which gas is allocated to market participants at DTS injection points, to both make the process quicker and reduce transaction costs.

A more substantial measure might be the introduction of one or more facilitated gas trading platforms at points outside, or on the edge of, the DTS. An obvious location for such a hub is at Longford. Other locations around the periphery of the DTS might also be considered.

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67 Submissions to the draft final report: Seed Advisory, p. 40; Origin, p. 11.

These facilitated gas trading platforms might be similar or identical to the GSH design at Wallumbilla and Moomba. Trading would be voluntary at a physical point on the system, perhaps even using the same trading software and front-end interface for market participants.

Using these platforms, market participants could choose to trade standardised gas products of a variety of different tenures and start dates. Prices of trade executed through the platform would be made available to the market, so that market participants are able to make more informed decisions regarding future gas trades.

While this option involves the facilitation of bilateral trades outside of the DTS, the DWGM would be retained and be substantially similar or identical to its current design. Having executed trades outside of the DTS, market participants would still be required to make bids/offers in the DWGM and be allocated access to the DTS on that basis.

To the extent that this option facilitated physical trades outside of the DWGM, the Commission expects that the proportion of genuine trades executed through the DWGM between two different counterparties (currently approximately 20 per cent) would decrease, as trades are instead executed outside of the DWGM. Those market participants that chose not to source their gas through bilateral trades could continue to do so through the DWGM. The DWGM would also continue to be used to facilitate spot trades of gas, perhaps arising as a consequence of unexpected changes to supply and demand conditions on the day.

4.2.2 Assessment of the option

Depending on the precise nature of changes to facilitate physical trade outside of the DWGM, this option is likely to be relatively low cost to implement. Even if one or more GSHs were to be introduced, the costs are unlikely to be extremely high given that the marginal implementation cost of additional hubs is relatively low, and two such hubs have already been implemented by AEMO.

Consideration would need to be given to the precise location of the physical hubs, taking into account physical access to the location. At Wallumbilla, AEMO has implemented "optional hub services", a model aimed at facilitating access to the exact trading location within the Wallumbilla compound. Consideration would need to be given as to whether facilitating access to the trading location is warranted were GSH(s) to be implemented in Victoria.

Effective risk management in the DWGM

The main advantage of this approach is that it would provide market participants an alternative means to manage price risk in the DWGM through facilitating flexibility in their physical positions. In effect, it would seek to "plug the gap" between trading spot physical gas on the DWGM and long-term physical gas through GSAs.

If trades were conducted through a facilitated trading market, such as a GSH, information regarding the price of trades would be available to the market, helping to define a forward reference price for gas.

However, the Commission is concerned that this approach will split liquidity between trades conducted through the DWGM and those conducted outside, particularly if multiple trading locations were facilitated. Concentrating trading at a small number of locations serves to enhance liquidity at those locations, which in turn leads to prices that reflect underlying supply and demand conditions.

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

Were persistent price differences to emerge between GSHs (or similar trading platforms) located at the edge of the DTS (Longford and Iona, say) this would indicate a constraint on the DTS between these locations. This would provide the AER and APA market based price signals that investment in capacity to transport gas on the DTS between these locations may be warranted, improving the regulated investment decision making process.

Nevertheless, while a market based price signal could be used to improve the regulated investment decision making process, investment would continue to not be underwritten by market participants, and so the risk of investment decisions would still ultimately be borne by gas consumers.

Competition in upstream and downstream markets

As with the options in the previous chapter, to the extent that this option improves market participants' ability to manage risk, this option may reduce barriers to market entry, reducing market concentration and so promote competition in upstream and downstream markets.

Trading between the DWGM and interconnected pipelines

This option would somewhat harmonise trading arrangements between Victoria and the rest of eastern Australia. Assuming that a GSH was implemented, market participants would have the option to manage their risk and trade through the same platform as at Wallumbilla and Moomba. This is likely to reduce transaction costs for market participants, and may improve the level of trading between Victoria and the rest of eastern Australia.

4.3 Forward trading at the DTS integrated into existing DWGM

4.3.1 Description of option

Under this approach, access to the DTS would be market carriage, as it currently is. In order to gain access to the DTS, market participants would be required to bid and/or offer all of their gas into the DWGM. Gas scheduling would be as it is currently – AEMO would schedule the lowest priced combination of gas to meet demand given constraints.

Market participants would be able to enter into trades ahead of the gas day though a voluntary, net pool exchange, perhaps similar to the Trayport exchange used at the gas supply hubs. Market participants would be able to agree to a particular price for a particular quantity of gas and delivery date(s). However, unlike the GSH design and the draft model, market participants would not be able to trade on the day through the exchange. Instead, on the day trades would continue to be made through the DWGM.

Two potential sub-options for how the forward trading could be integrated into the on-the-day DWGM are given below.

Outstanding trades automatically bid/offered into the DWGM

One approach would be that at a cut off time before the start of the gas day, market participants' outstanding net positions for the upcoming gas day would be automatically bid or offered into the DWGM. So, for example, market participants who are net sellers of gas going into the day would have the net quantity of gas they have pre-sold automatically offered to the market at the market floor price. Similarly, net buyers of gas going into the day would have the net quantity of gas they have pre-bought automatically bid out of the market at the market price cap. In this way, the issue of conflicting pre-agreed trades with the daily and intra-day allocation of capacity would be largely (but importantly, not entirely) addressed, because offers and bids made at the market floor price and cap price respectively are likely to get scheduled and hence gain access.

Pre-agreed trades could be settled through the DWGM at the pre-agreed price, while the remaining trades on the day would continue to be settled through the DWGM at the market price. In this way, both settlement and gas quantities would balance - both of which are prerequisites for the market's design.

However, offering and bidding gas at the market floor price and cap price respectively does not guarantee access. At times of transmission constraint such that all offers/bids at the floor/cap cannot be simultaneously met, the dispatch engine schedules those market participants that hold sufficient AMDQ rights, and constrains off (that is, does not provide access to) some or all of those market participants that do not hold AMDQ rights.[68]

Constraining off injections or withdrawals that were required to meet pre-arranged trades is problematic for the purposes of settlement. For example, market participant A and market participant B have pre-arranged a trade on the exchange for 10GJ of gas at

68 Of course, in some circumstances such as a breakdown of transmission equipment, even AMDQ holders might not be able to all be simultaneously scheduled. In normal operating conditions, however, the number of AMDQ rights are consistent with the physical capacity of the network and hence AMDQ holders do not need to be constrained off when the holders offer/bid their gas at the floor/cap.

$4/GJ for delivery in ten days' time. After ten days, the seller (market participant A) is constrained off, meaning that market participant B's gas requirements are sourced from other sellers on the DWGM, at the market price of, say, $5/GJ. While delivery of gas would therefore be assured (to the extent that it is currently through the DWGM), in order for settlement to balance the other sellers from whom B's gas came from must be paid $5/GJ - that is, $1/GJ more than the pre-agreed price between market participants A and B.

In order for settlement to balance (which it must) market participants A or B must collectively bear the financial risk of one or other of the counterparties being constrained off. This could be achieved by:

- increasing the firmness of scheduled gas injected/withdrawn pursuant to pre-agreed trades, by making such gas firmer than AMDQ or restricting pre-agreed trades to those that can be backed by AMDQ. This would appear to undermine the firmness of AMDQ or reduce the potential pool of counterparties.
- the risk being borne in full by the counterparty to the market participant who was constrained off. However, depending on the likelihood of a market participant being constrained off, this would seem to undermine the rationale of the forward market because its counterparty would be exposed to the market price after all.
- the risk being borne in full by the market participant who was constrained off.

Were the risk in full to be borne by the market participant which was constrained off that market participant is in effect purchasing gas on the spot market to meet its pre-agreed trade, rather than delivering the gas itself to do so. This could be considered a form of deviation payment: market participants which deviate from their pre-agreed trades would have the quantity they deviate settled at the ex post market price.

Outstanding trades not automatically bid/offered into the DWGM

If the market participant who is constrained off bears the risk, the underlying rationale for outstanding trades to be bid/offered into the market automatically at the market floor/cap may no longer apply.

Instead, a market participant could choose not to deliver/receive gas at all, or to only do so if the market price was above or below a certain amount by making an offer/bid into the DWGM at that price. It might do this if it valuation of the gas had changed substantially since it struck the pre-agreed trade.

For example, suppose that market participant C owns a factory and has pre-agreed a price for gas delivery. However, the factory has had an unexpected shutdown, meaning that it cannot use the gas on a particular day. Were the pre-agreed trade to be entered into the DWGM bid stake at $800/GJ, the gas would be likely to be scheduled to the market participant, despite it not wanting it (that is, it values it at $0/GJ). The market participant might prefer not to be scheduled (given that it places no value on the gas), and so would be able to not bid into the DWGM for the gas. Consequently, it would face a (negative) deviation payment, effectively selling the gas it has pre-bought back to the market at the spot price - allowing it to recoup some of the value of the pre-agreed trade, or even profit if the market price exceeds the pre-agreed price.

4.3.2 Assessment of option

Effective risk management in the DWGM

Primarily, this option seeks to improve the effectiveness of risk management in the DWGM by providing market participants with an alternative means to manage price risk, through the DWGM itself.

With regard to the issue of the allocation of risk of being constrained off, it may be appropriate for this to sit with the market participant who is constrained off. Through the purchase of AMDQs, it is able to manage this risk, unlike its counterparty.

It may also be appropriate for market participants to be able to choose whether they physically deliver gas to meet their pre-agreed trades, or purchase gas on the spot market to do so. That is, market participants' outstanding trades going into the day would not be automatically bid/offered to the market at the market floor/cap price. Under this arrangement, market participants do not bear any risk of their counterparty not being scheduled. It therefore may be appropriate to give market participants the choice as to how to meet their pre-agreed trades, either through the spot market or physical delivery.

The Commission notes were market participants able to choose whether they physically deliver gas to meet their pre-agreed trades, or purchase gas on the spot market to do so, the outcomes appears near identical to the financial derivatives market currently administered by the ASX.[69] Under a swap contract, a market participant's revenue is determined as follows:

- Revenue = Scheduled imbalance x market price (DWGM settlement)

  + (pre-agreed price - market price) x pre-agreed quantity (derivative settlement)

Mathematically, this is identical to settlement based on the pre-agreed price and quantity, adjusted by a deviation payment made on the difference between gas pre-agreed for trading and gas scheduled:

- Revenue = pre-agreed price x pre-agreed quantity

+ (scheduled imbalance - pre-agreed quantity) x market price.

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69 Indeed, arguably were market participants able to choose whether they physically deliver gas to meet their pre-agreed trades, or purchase gas on the spot market to do so, this *is* financial forward trading, rather than physical forward trading.

There may be some advantages of AEMO running such a forwards market as opposed to the ASX or another body, such as pooling of individual participant prudential requirements, reduced market fees and potentially removing the obligation to hold an Australian Financial Services Licence (AFSL). But the Commission considers that the issues that have limited the development of a financial derivatives market may equally limit the use of this option, without also implementing one or more of the options to facilitate financial derivative trading (chapter 3). Consequently, it is not clear that this option will improve the ability of market participants to manage risk. The Commission welcomes feedback in this regard.

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

This option does not appear to substantially impact on signals and incentives in and use of pipeline capacity. That is, the option does not represent a change in this regard compared to the current DWGM.

Trading between the DWGM and interconnected pipelines

If a market platform such as that used at the GSHs were to be used to facilitate trade prior to the gas day in Victoria, the partial alignment in DWGM and GSH market designs may lower transaction costs and facilitate trade between the DWGM and interconnected pipelines.

Promoting competition in upstream and downstream markets

As with the other options in this and the previous chapter, to the extent that this option improves market participants' ability to manage risk, this option may reduce barriers to market entry, reducing market concentration and so promote competition in upstream and downstream markets.

4.4 Forward trading with net facilitated daily gas market

4.4.1 Description of the option

As with the option of improving trading outside the DWGM described in section 4.2, this option involves allowing market participants to trade gas on a voluntary, net exchange (similar or identical to Trayport as used at the GSHs) prior to a ‘gate closure’ at some point before the start of the gas day.

Following gate closure, a voluntary net market (as compared to a gross pool DWGM) would apply to enable AEMO to manage flows and system security. That is, AEMO would have primary balancing responsibility.[70]

70 AEMO has primary balancing responsibility in the DWGM. In the draft model AEMO has a residual balancing role (see section 2.2).

This option was considered in the draft final report to this review in respect of transition measures to the draft model.[71]

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

Under the simplest approach, market participants would be required to nominate injections and withdrawals at the time of gate closure consistent with their firm entry and exit rights, assuming that they will be 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

71 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final report, 14 October 2016, pp. 94-95.

net market process.[72] Any deviations would be addressed by AEMO trading gas on their behalf through the scheduled auction, settled at the auction clearing price.

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 would 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 buy or sell 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 3.3, 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.

More complex approaches to this option would allow market participants to:

- trade with one another (rather than just with the system operator) after gate closure
- plan on a deficit or surplus in advance, and so nominate unbalanced positions at gate closure, and then have the system operator source their gas during the day (for a cost).

This approach is a hybrid between the existing DWGM and the draft model:

- Like the DWGM, AEMO would have primary responsibility to balance the system, "buying" or "selling" gas through a scheduled approach (like the DWGM), and passing these costs through to those market participants which deviate in the form of deviation charges
- Like the draft model, market participants would:
  - be able to trade gas ahead of the gas day

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

— 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.

4.4.2 Assessment of the option

Effective risk management in the DWGM

As with the other options raised in this chapter, 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 draft 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 draft 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 confidence that it would be able to source gas for balancing purposes as and when needed.

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

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 6.4.

Trading between the DWGM and interconnected pipelines

This option would introduce a trading mechanism similar to that at Wallumbilla and Moomba for greater than day ahead trades, but would retain an on the day trading market similar to the existing DWGM.

Consequently, this option may reduce transaction costs for market participants operating across the east coast and improve trading between across the markets. However, this also means two market designs would continue to operate, with potentially additional cost and complexity.

Promoting competition in upstream and downstream markets

As with the other options in this and the previous chapter, to the extent that this option improves market participants' ability to manage risk, this option may reduce barriers to market entry, reducing market concentration and so promote competition in upstream and downstream markets.

5 Improving AMDQ rights

The Victorian DTS is the only gas transmission system operating under a market carriage model in eastern Australia.[73] Under the market carriage model, market participants utilising the DTS cannot reserve firm capacity on a pipeline and are instead implicitly allocated capacity through the DWGM.

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. However, they may hold authorised MDQ or AMDQ cc (collectively known as AMDQ),[74] which provides some limited physical and financial rights.

The amount of AMDQ is consistent with the physical capacity of the system, meaning that under normal operating conditions (that is, other than when there is transmission equipment failure or another significant issue on the network) the physical and financial rights provided by AMDQ can be honoured.

Broadly, AMDQ provides the following physical and financial rights:

- *Injection tie-breaking rights:* market participants with AMDQ are physically scheduled in preference to those without AMDQ when there are tied injection bids in the DWGM. This is particularly critical when the system is congested or supply is limited (for example during maintenance), and most market participants try to get as much gas injected into the system as possible by bidding their gas at $0/GJ (the market floor price).

- *Withdrawal tie-breaking rights:* these provide the same physical benefits as described above for the injection tie-breaking rights.

- *Limited physical protection against curtailment for tariff D sites:* tariff D sites (large industrial and commercial sites) with no authorised MDQ are curtailed ahead of those with authorised MDQ in the first stages of a DTS emergency.

- *Uplift hedge protection:* market participants with AMDQ can create a financial hedge against congestion uplift provided that they inject sufficient gas at the relevant close proximity point (CPP). Congestion uplift payments results from the need to inject out of merit order gas offered at a price higher than the market price, and are paid by those market participants whose consumption exceeds

73 Market carriage in Victoria (and its difference to contract carriage elsewhere) is covered in detail in AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, stage 1 final report, 23 July 2015, Sydney, pp. 47-50.

74 Authorised MDQ and AMDQ cc are collectively known as AMDQ. Throughout this chapter, the distinction between authorised MDQ and AMDQ cc is relevant. Consequently, this chapter will refer to authorised MDQ and AMDQ cc when referring to the specific right, and AMDQ when referring to the both authorised MDQ and AMDQ cc. 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.

their authorised maximum interval quantity (AMIQ) resulting from their AMDQ holdings.

AMDQ are specific point-to-point rights, with the benefits only applying when market participants are injecting and withdrawing at specific locations.

AMDQ can also be re-allocated between locations and market participants under certain circumstances and following specific procedures.

This chapter introduces some key concepts regarding capacity rights in box 5.1 that are relevant for both this chapter and chapter 6. It then explores options that might improve the efficiency of creating, allocating and reallocating capacity rights between market participants and locations. To this end, the chapter considers options to improve:

- the creation of AMDQ cc, through market participants being able to signal their intention to buy AMDQ cc before investment is made in the underlying DTS capacity
- the reallocation and trading of AMDQ
- the locational characteristics of AMDQ cc.

Box 5.1 Key capacity rights concepts

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

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)[75]
- financial compensation such that they are indifferent to whether they are provided physical access (in the case of firm financial rights).[76]

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.

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,[77] to specific customer sites or to a system withdrawal point at an interconnected facility.[78]

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

76 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.

77 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.

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

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 draft 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 6.4 is an example of this hybrid approach to capacity allocation.

5.1 Market signalling for AMDQ cc prior to capacity expansions

Authorised MDQ was first allocated at market commencement in 1998 to tariff D customers 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). There is no designated permanent owner of tariff V authorised MDQ. Instead, gas retailers are allocated the market rights associated with tariff V authorised MDQ in proportion to the aggregate of their tariff V customers' usage. This allocation is adjusted on a daily basis to reflect customer transfers, which continually change the tariff V allocations between retailers. 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.[79] 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) 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.

5.1.1 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 draft 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.[80]

Further detail on these three mechanisms is provided in box 5.2.

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

80 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final technical report, 21 October 2016, pp. 74-75.

Box 5.2 Open seasons, integrated auctions and hybrid options

Open seasons

The term "open seasons" refers to distinct periods of time when parties can request capacity for future periods. Open seasons serve to confirm the collective interest of market participants in making binding commitments to purchase capacity and can relate to incremental capacity only, or a combination of existing unsold capacity and incremental capacity. Open seasons may include both a "non-binding" and a "binding" phase. The non-binding phase precedes the binding phase and provides a preliminary gauge on the collective demand for future capacity use by parties.

In a recent review carried out by the Agency for the Cooperation of Energy Regulators (ACER), a number of concerns were raised with the way open seasons have been conducted in Europe. The main concerns were that they tend to provide little transparency about the value of the investment, allocation of risk, how tariffs are derived, the investment tests employed and how capacity is allocated.[81]

Integrated auctions

The term 'integrated auction' refers to an auction that can be used to signal the need for incremental capacity and allocate both existing and incremental capacity.

To carry out an integrated auction, a schedule of increasing price steps must be developed against which parties can indicate their willingness to pay for capacity in the form of a quantity bid for each price. Each price step must be paired with a potential incremental quantity of capacity and would reflect the cost to deliver this capacity. National Grid (Great Britain) develops 20 price steps each of which is associated with a 2.5 per cent increase in capacity (equivalent to a 50 per cent capacity increase) and is based on the long run marginal cost.

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

- demand being less than or equal to existing baseline capacity, then the existing capacity would be allocated to the bidding parties at the existing reserve price
- demand exceeding the existing baseline capacity, then if the investment test[82] is:

81 Frontier, *Impact Assessment of Policy Options on Incremental Capacity for EU Gas Transmission*, February 2013, pp. 36-37.

82 In Great Britain, the investment test requires the present value of revenue from the bids for incremental entry capacity to exceed a 50 per cent threshold for up to 32 quarters from release. The

— satisfied and a decision is made to expand capacity, the bidding parties would pay the price step associated with the relevant capacity expansion, or

— not satisfied, existing capacity would be allocated at the price where demand is less than or equal to the existing baseline capacity.[83]

The main benefits of integrated auctions are that they are non-discriminatory and provide a market based mechanism to allocate existing and incremental capacity. They can, however, be costly to carry out and the value in carrying out regular auctions is questionable if there is little indication of the need for additional capacity.

Hybrid open season-integrated auctions

The hybrid open season-integrated auction overcomes some of the perceived shortcomings of the integrated auction by requiring a non-binding open season to be conducted before a decision is made to proceed with the integrated auction and the design and costing phases can start. If the open season reveals that there is sufficient interest amongst market participants to expand the capacity of the pipeline, then the integrated auction would proceed. If, on the other hand, there is insufficient interest then the integrated auction would not be carried out and existing capacity sold through the standard auction process.

The Commission preferred a hybrid open season-integrated auction for entry and exit capacity in the draft model, because it would allocate capacity in an efficient, transparent and non-discriminatory manner.[84] Nevertheless, there may be other more suitable approaches 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.

5.1.2 Assessment of option

Effective risk management in the DWGM

This option may improve the ability of market participants to obtain AMDQ cc and hence improve their ability to manage congestion related risk in the DWGM.

Signals and incentives for efficient investment in and use of 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

investment test in rule 79(2)(b) of the NGR, on the other hand, requires the present value of the incremental revenue from forecast demand to exceeds the present value of the investment cost.

83 If the auction cleared at price step 2 or above, it may be possible to consider smaller expansions.

84 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, draft final technical report, 21 October 2016, pp. 75-76.

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 effects described at the beginning of this chapter.

It is therefore not clear that APA and the AER will be easily able to 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 (see chapter 6).

Were this option taken forwards, careful consideration would need to be given to the specific method by which capacity is allocated. Complex integrated auctions in the case of AMDQ cc may be too high cost to justify implementing given that the prospective benefits may be low.

Trading between the DWGM and interconnected pipelines

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 the DWGM and those facilities.

Promoting competition in upstream and downstream markets

Enhanced transparency and certainty in the allocation process of AMDQ cc could promote competition and reduce barriers to entry for new market participants.

5.2 Improve AMDQ and AMDQ cc allocation and trading

AMDQ are, in some circumstances, tradeable capacity rights:

- AMDQ cc are held by market participants and can be traded among themselves
- Authorised MDQ (tariff D) are primarily held by large industrial consumers and can be traded among themselves and to other market participants[85]
- Authorised MDQ (tariff V) are automatically and dynamically allocated to market participants in proportion to their retail load and therefore cannot be traded

85 A limited amount of authorised MDQ has been purchased from the original large industrial consumers by retailers and are therefore no longer held by a large industrial consumer.

- as Authorised MDQ (tariff D and tariff V) are primarily held by end consumers, retailers supplying these consumers cannot trade these rights, but can transfer some of the associated benefits.

The box below briefly describes the current process that market participants need to go through for the transfer (trade) of AMDQ, and the transfer of benefits associated with these rights.

Box 5.3 AMDQ transfers

Permitted transfers of authorised MDQ

Transfers of authorised MDQ can only be undertaken between:[86]

- two tariff D withdrawal points
- a tariff D withdrawal point and the reference hub (or vice-versa), or
- two parties at the reference hub.

Site to site authorised MDQ transfers involve two steps: first from the originating site to reference hub, and then from reference hub to the destination site.

Site to reference hub, reference hub to site, or reference hub to reference hub transfers are simpler, each being a single step.

Permitted transfers of AMDQ cc

Transfers of AMDQ cc can only be undertaken between market participants at the reference hub. However, AMDQ cc must then be nominated by the new holder, either to the reference hub or to a different location.

Restrictions of transfer quantities

Not all transfers of authorised MDQ are consistent with the physical capacity of the DTS. Consequently, AEMO applies diversity and locational factors to account for the effect of pipeline network dynamics on the value of authorised MDQ when transferred.[87] Necessarily, transfers of AMDQ cc are consistent with the physical capacity of the DTS because they happen between two market participants both at the same location - the reference hub. A subsequent nomination of AMDQ cc to other locations is subject to locational factors to ensure the nomination is consistent with the physical capacity of the system.

Initiating a transfer or nomination process

Market participants need to submit a form to AEMO no less than five business days in advance of the required start date for a transfer to take effect.

86 Unless otherwise stated, the information in this box references: AEMO, *Wholesale Market AMDQ Procedures (Victoria)*, 25 October 2016.

87 AEMO, *AMDQ transfer algorithms for the transfer of authorised MDQ and AMDQ credit certificates*, 3 April 2012.

Processing time

AEMO will use reasonable endeavours to process transfers within six business days of AEMO receiving a form.

Publication on market information bulletin board (MIBB)

AEMO publishes the aggregate amount of AMDQ transferred on each gas day on the market information bulletin board, and the indicative amount of available spare capacity at selected locations within the DTS.

Agency injection hedge

Because retailers do not own the large majority of authorised MDQ (which are owned by end customers) they are unable to transfer these rights. Nevertheless, retailers are able to transfer some of the associated benefits of authorised MDQ to other market participants.

This is undertaken by a retailer allocating a quantity of its scheduled injection to be used as an agency injection hedge nomination (AIHN) for one or multiple recipient market participants at a close proximity injection point. The recipient market participant receives the congestion uplift hedge created by injecting gas at the close proximity point, while the retailer continues to receive the injection tie breaking rights.

There are a number of issues that may be restricting the ability of market participants to trade AMDQ (or to allocate the associated benefits of authorised MDQ) in an efficient manner. Some of the issues are highlighted below:

- *Allocation of authorised MDQ at Longford.* Authorised MDQ associated with Longford is allocated for tariff V customers between market participants based on their customer base. This may give rise to a situation where a market participant has been allocated more authorised MDQ than it has contracted injection capacity at Longford. Since authorised MDQ allocated to tariff V customers cannot be transferred, it is effectively stranded.

- *Allocation of AMDQ cc.* AMDQ cc is released through the AEMO auction in tranches, often for five years in line with APA's access arrangement period, which means that new entrants within the five year period are unable to obtain AMDQ cc if the full allocation has been sold, no additional capacity is created through the APA led process (that is, with associated costs not included in the regulated asset base), and no other market participant is willing to sell.

- *Lengthy processing time for transfers.* Market participants have little ability to trade short-term AMDQs as it can take six business days to complete the transfer.[88]

88 The Commission understands this is due to AEMO: having to undertake flow modelling to make sure the transfer is possible; validating that the applicant is the rightful owner of the AMDQ; and having to make manual database changes.

- *Complex process to acquire market benefits.* It can be a confusing process to obtain AMDQ rights (or the associated benefits of authorised MDQ). Complicating factors include the diversity and locational factors which determine the value of AMDQ transferred or nominated to other locations, and the agency injection hedge process.

- *Search and transaction costs.* As market participants have to bilaterally find one another to enter into a trade (or to allocate the associated benefits of authorised MDQ), there may be considerable search and transaction costs, which may deter otherwise efficient trades and be time consuming.

In 2013-14, the AEMC considered a rule change request submitted by AEMO seeking to introduce a trading platform mechanism that would facilitate market participants transferring all or part of their portfolio of financial benefits associated with holding AMDQ to other market participants operating in the DWGM.[89] Due to circumstances at the time (namely revised costs and timeframes for implementation) the Commission decided not to make a rule in its final determination.[90]

In this section we revisit the concept of creating a trading platform for secondary trading of AMDQ.

5.2.1 Description of option

An electronic trading platform could be introduced where market participants could anonymously post bids and offers to transfer all or part of their portfolio of financial and/or physical benefits associated with holding AMDQ to other market participants operating in the DWGM.

The mechanism would allow for the transfer of benefits, not of the rights themselves, because authorised MDQ are primarily owned by end consumers, not their retailers.

Alternatively, AMDQ cc ownership could be fully transferred to other market participants through the trading platform, as could authorised MDQ when the seller is the rights holder (most likely an incumbent tariff D customer). However, in the case that the seller is a retailer supplying the authorised MDQ holder, the platform would be limited to trading only the rights associated with authorised MDQ.

The platform would automatically match bids and offers and execute the trade. This trading platform could be similar to that recommended by the Commission in the east coast review stage 2 final report with regard to the trading of point-to-point capacity outside of the DTS.[91]

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89 See: http://www.aemc.gov.au/rule-changes/portfolio-rights-trading.

90 AEMC, *Portfolio Rights Trading*, rule determination, 27 November 2014, Sydney.

91 Refer to Recommendation 7 at AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, stage two final report, 23 May 2016, Sydney.

Trades between different locations would still be subject to the transfer algorithm, to ensure that the trade was consistent with the underlying physical capacity of the system. The transfer algorithm could possibly be integrated into the trading platform, depending on the cost and complexity of doing so. Alternatively, trades could be conducted exclusively at the reference hub, with transfers/nominations to other locations taking place through a separate step outside of the platform.

The proposed trading mechanism would:

- allow for the transfer of entitlement to the benefits associated with AMDQ between market participants in a timelier manner than the current transfer procedures
- facilitate liquidity in trading of the benefits associated with AMDQ
- improve price discovery by market participants
- protect the identity of market participants which might have concerns around confidential or commercially sensitive information when trading bilaterally.

If market participants were better able to access underutilised uplift hedge or tie-breaking rights, for example through improved secondary trading of AMDQ, this may improve:

- the ability of market participants to manage the risk of uplift hedges or physical congestion
- the quality of decisions to invest in the DTS, because market participants would have better information and opportunities to trade existing AMDQ rather than seeking investment capacity to create new AMDQ.

5.2.2 Assessment of option

The option described in this section might be relatively easy to implement and would minimise disruption to the current activities in the market.

Effective risk management in the DWGM

This option may improve the ability of market participants to obtain AMDQ and hence improve their ability to manage congestion related risk in the DWGM.

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

Creating a mechanism which enables underutilised AMDQ to become available to market participants who value it more highly may improve investment signals in the DTS. If the ability of market participants to access AMDQ is restricted due to an illiquid secondary trading market, this may prompt market participants to seek the creation of additional AMDQ cc (perhaps through underwriting additional capacity through the auction of AMDQ cc rights as described in section 5.1).

This option might efficiently defer this investment if market participants are otherwise able to obtain AMDQ through the secondary market rather than the primary market.

Having said this, as noted in section 5.1, AMDQ cc might not be a sufficiently firm capacity right to inform the regulatory investment decision making process in a meaningful manner. It is therefore not clear that improving the secondary capacity market for AMDQ will significantly improve investment signals in the DTS. Nevertheless, a better facilitated market for secondary trading of capacity rights that are firmer than AMDQ (as described in chapter 6) might be warranted.

Trading between the DWGM and interconnected pipelines

To the extent to which this option better facilitates market participants securing (non-firm) capacity rights to interconnected facilities, this option may allow for improved trading between the DWGM and those facilities.

Promoting competition in upstream and downstream markets

Enhanced transparency and certainty in the allocation process of AMDQ cc could promote competition and reduce barriers to entry for new market participants.

5.3 Withdrawal AMDQ cc

The focus of AMDQ has historically been on meeting intrastate demand primarily in or around Melbourne, rather than to ship gas to or beyond the periphery of the DTS. However, with the changing dynamics in the east coast gas market there is growing demand to be able to move gas from the DTS inter-state or into storage at Iona, to be used in the DTS at a later date.

All AMDQ cc are initially created as a point to point right between an injection point (for example Culcairn or Iona) and the reference hub at Melbourne. These rights are consistent with the underlying physical capacity of the system between the injection point and the reference hub.

Market participants are then required to nominate their AMDQ cc to a withdrawal point (which may be the reference hub or a different location).

In order to nominate AMDQ cc to a system withdrawal point at an interconnected facility (for example at Culcairn or Iona), the market participant must provide satisfactory evidence to AEMO that it, or a counterparty, holds a corresponding quantity of firm capacity rights on that interconnected facility.[92] The nomination must

[92] The need to provide evidence of firm capacity at an interconnected facility was introduced in 2014, after a procedure proposal request submitted by APA. See: AEMO, *Notice to participant of AEMO's decision on making the Wholesale Market AMDQ Procedures (Victoria)*, 10 June 2014.

also be consistent with the underlying physical capacity of the DTS, with AEMO applying locational factors to any nominations as noted in box 5.3.

The nomination process is first-come-first serve, with AEMO processing viable nomination requests in the order they receive them.

At Culcairn, the amount of firm capacity available north of Culcairn is consistent with the capacity in the DTS south of Culcairn. Market participants that have a newly acquired firm contract north of Culcairn would have sufficient confidence that they (alone) will be able to nominate their AMDQ cc to withdraw at Culcairn. This is because other parties would be prohibited from doing so as they have insufficient firm capacity at the interconnected facility. Therefore there may be an incentive to underwrite firm contract carriage capacity outside of the DTS north of Culcairn and capacity to Culcairn within the DTS, utilising any newly created capacity.

However, at Iona the total amount of firm capacity on interconnected facilities outside of the DTS far exceeds the amount of capacity on the South West Pipeline from Melbourne to Iona. This is because there are multiple facilities interconnected at Iona which collectively have a capacity greater than the South West Pipeline (for example, the SEA Gas pipeline and the Iona gas storage facility). Were capacity to be underwritten by a market participant in order to create new AMDQ cc which could be nominated to Iona, the market participant would have no ability to ensure that existing AMDQ cc was not then nominated to Iona by a different market participant because it was first to make a nomination request after the capacity was created. This may be prohibiting the ability of AMDQ cc to be used as a signal for market-led investment in the DTS for withdrawal at certain interconnected capacity.

5.3.1 Description of option

Under this approach, AMDQ cc could be initially created with a withdrawal point different to the reference hub. This could be achieved by:

- Removing the requirement for AMDQ cc to be automatically specified to the reference hub, and therefore allowing for the creation of rights between any injection point and any withdrawal point. Effectively, this couples together the currently distinct processes of AMDQ cc creation and AMDQ cc nomination.

- Creating rights between the reference hub and a withdrawal point (creating "exit" AMDQ cc) to mirror and complement existing ‘entry’ AMDQ cc from an injection points to the reference hub. In this context, exit AMDQ cc would provide the same benefits to rights holders as current AMDQ cc do and would continue to be point-to-point. Market participants could then purchase entry AMDQ cc from an injection point to the hub, and exit AMDQ cc from the hub to a withdrawal point, providing them the benefits of AMDQ cc along the whole of their route.

By initially creating rights with withdrawal points other than the reference hub, another market participant would be unable to nominate its existing AMDQ cc to that point, because the transfer algorithm would already specify the newly created rights at the withdrawal point and therefore not allow the nomination. This may provide market participants greater confidence signal investments through their willingness to underwrite capacity to create AMDQ cc.

5.3.2 Assessment of option

Effective risk management in the DWGM

As with the other options in this chapter, this option may improve the ability of market participants to obtain AMDQ and hence improve their ability to manage congestion related risk in the DWGM.

Careful consideration would need to be given to how a number of the benefits of holding AMDQ would function in the case of exit AMDQ cc. For example, protection against uplift hedge proved by AMDQ is currently activated through an injection. Clearly, in the case of exit AMDQ there would not be an associated injection, so it may be appropriate that exit AMDQ cc do not provide uplift hedge protection.

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

The primary rationale for this option is to better enable market-led investment in DTS capacity to system withdrawals points, most notably those where the quantity of firm capacity on the other side of the DTS far exceeds the corresponding pipeline within the DTS (that is, at Iona).

Market participants can be confident that in underwriting capacity and purchasing AMDQ cc they will be able to nominate those AMDQ cc consistent with the newly created capacity.

As with other options in this chapter, it is not clear whether AMDQ are sufficiently firm rights to allow for meaningful market-led investment signals.

Trading between the DWGM and interconnected pipelines

As with the other options in this chapter, 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 the DWGM and those facilities.

Promoting competition in upstream and downstream markets

Enhanced transparency and certainty in the ability of market participants to nominate AMDQ cc to their preferred location could promote competition and reduce barriers to entry for new market participants.

6 Increase the firmness of capacity rights

As discussed in chapter 5, 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 the DTS Access Arrangement. As discussed in chapter 2, putting to one side the free-rider problem which arises from allocating capacity through the DWGM, the current regulatory approach to expansion has two substantial drawbacks compared to a market-led approach:

- the regulator is unlikely to have the same information or incentives to make efficient decisions compared to a market participant
- if an inefficient investment decision is made, consumers, rather than the market participant, would bear the cost of this decision.

However, while users cannot hold firm capacity, they may hold AMDQ which act as quasi capacity rights and affords the holder certain limited financial and physical benefits while being consistent with the allocation of capacity dynamically through the gas commodity market.[93]

This chapter explores five options that might improve the firmness of the current quasi capacity rights held by market participants (addressing the free-rider problem):

- improved scheduling priority – where there are constraints, prioritising AMDQ holders over non-AMDQ holders where offers are under the market price
- firmer financial rights – AMDQ holders would receive some financial compensation should they not be scheduled
- settlement residue rights – 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
- firm physical entry and exit capacity rights with a net market for residual capacity allocation
- firm physical point-to-point capacity rights.

93 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.

6.1 Improved scheduling priority

6.1.1 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.[94]

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, in the event of a constraint such that two market participants' gas cannot both be scheduled, a $4 offer from a non-rights holder would continue to be scheduled in preference to an $8 offer from a rights holder, if the market clearing price is $5.

6.1.2 Assessment of option

This approach is consistent with the retention of the current market carriage model and the gross gas pool market and could be relatively easy to implement.

However, this approach 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.[95] Inevitably, this approach moves away from this dispatch – and as a result is less efficient.

Effective risk management in the DWGM

This option reduces the likelihood that participants with AMDQ will be constrained off, therefore 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

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

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

firmness of the capacity rights. Given that the rights are only slightly firmer in this option, this benefit may not be significant.

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

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.

Trading between the DWGM and interconnected pipelines

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 the DWGM and those facilities.

Promoting competition in upstream and downstream markets

This option does not appear to substantially impact on the level of competition in upstream or downstream markets.

6.2 Firmer financial capacity rights

6.2.1 Description of option

The firmness of capacity in the DTS could also be improved by allocating financial capacity rights, which in turn could improve incentives for market-led investment.

This option involves translating the existing AMDQ mechanism into firmer financial rights by introducing:[96]

- 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.

We note that 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.[97]

96 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.

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.

6.2.2 Assessment of option

Effective risk management in the DWGM

This option increases the financial firmness associated with capacity rights, therefore improving the ability for participants to manage congestion related risk in the DWGM.

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

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.

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97 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.

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
- however, 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 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 6.3.

Trading between the DWGM and interconnected pipelines

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 the DWGM and those facilities.

Promoting competition in upstream and downstream markets

This option does not appear to substantially impact on the level of competition in upstream or downstream markets.

6.3 Zonal pricing with settlement residue rights

6.3.1 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.[98]

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.

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 6.1.

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 6.1 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.

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

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 discussed in section 3.1.

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, it may be appropriate that any party is allowed 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 6.3.2. Box 6.2 towards this end of this section discusses nodal pricing, which is essentially very many zones, one at each node in the network. Box 6.3, 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.

6.3.2 Assessment of option

Effective risk management in the DWGM

This approach introduces inter-zonal pricing risk. For example, if a market participant injects in one zone and withdraws in another zone, 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, for the reasons discussed below, 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 potentially split liquidity. The extent to which liquidity would be split would be a function of the number of zones created.

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

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 6.1 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. 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.

Trading between the DWGM and interconnected pipelines

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 the DWGM and those facilities.

Promoting competition in upstream and downstream markets

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.

Box 6.2 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 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. As such, a price for gas at each node would be determined and settlement would be on the basis of this nodal price.

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 6.3 Optional firm access (OFA)

Optional firm access is an alternative financial transmission rights model developed by the AEMC for the NEM.[99] The model was not considered to further the National Electricity Objective at the time but is under regular review.

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

- 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:[100]

- 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 was not 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.

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

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

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

6.4.1 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.[101]

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.[102]

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 4.4).

This option is similar to the draft 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 draft model, mechanisms to allow for the efficient and liquid trading of firm capacity between market participants would be required.

101 Firm physical entry and exit capacity is a feature of the draft model.

102 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.

6.4.2 Assessment of option

Effective risk management in the DWGM

Combined with a forward physical market as described in section 4.4, this option would provide market participants additional options and flexibility to manage price and volume risk.

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

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.

Trading between the DWGM and interconnected pipelines

Fully firm entry and exit capacity rights are more consistent with the point-to-point contract carriage arrangements that exist outside the DTS than current arrangements. They would allow parties to enter into contracts for transport of gas from the DTS to interconnected pipelines, thereby providing additional certainty for market participants wishing to trade or transport gas inter-state.

Were this option to be combined with a forward physical market as described in section 4.4, trading arrangements other than on the day could be unified with those at Wallumbilla and Moomba. This may reduce transaction costs and barriers to entry for market participants wishing to participate in both the DWGM and at GSHs.

Promoting competition in upstream and downstream markets

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 the large 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.

6.5 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.[103]

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.

6.5.1 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).[104]

Under this sub-option, contract carriage would be introduced along the high capacity 'spokes' of the DTS plus the outer ring main (see figure 6.1).[105] 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[106] as well as on the portions of the contract carriage pipelines that is contracted by AEMO. AEMO would remain the market

103 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.

104 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.

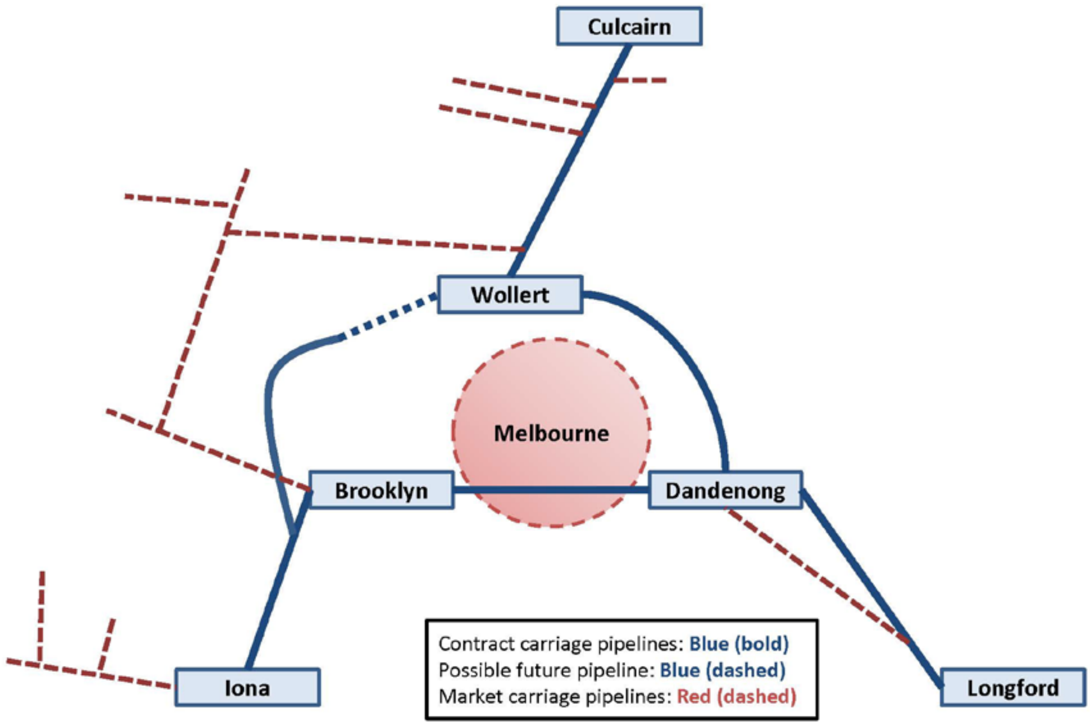
105 For example, contract carriage could operate on: South West Pipeline (Iona to Brooklyn); Longford to Dandenong; Culcairn to Wollert; Dandenong to West Melbourne.

106 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.

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 6.1: 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).

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.[107]

Participants directly connected to the CC pipelines (for example gas powered generators and other large users) and participants that wish to transport gas through Victoria (or between Longford and storage at Iona) 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).

107 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.

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[108] 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.

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 with a high probability of being scheduled.

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.

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108 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.

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.

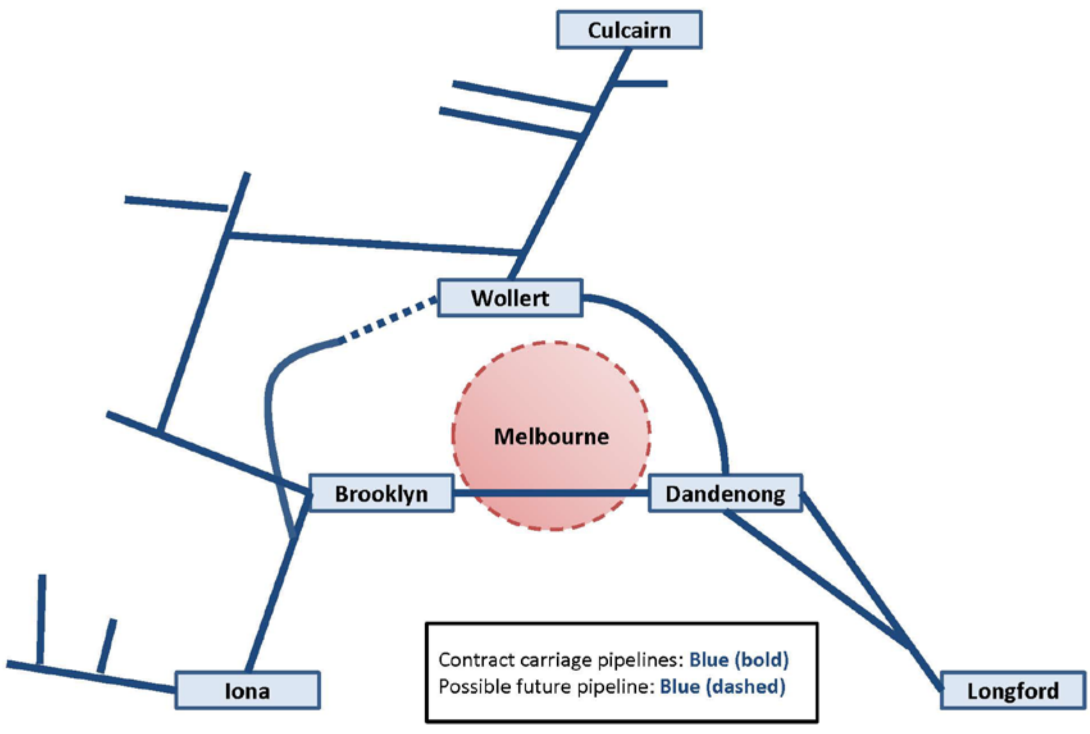
APA would also have access to risk management tools through the GTAs for the CC pipelines. APA could bilaterally negotiate for the contractual curtailment of non-essential loads.

6.5.2 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 6.2: 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.

6.5.3 Description of sub-option 3

Contract carriage would be applied to all transmission pipelines in the DTS (see figure 6.2 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[109] 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.

6.5.4 Assessment of options

The main benefit of creating fully firm capacity rights is to improve the incentives for market-led investment in the DTS.

However, some of the potential issues with these options that would need to be considered include the following:

- 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

109 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.

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 little 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.

Effective risk management in the DWGM

The sub-options that retain the DWGM may give participants greater flexibility to choose whether they want to remain within the DWGM or arrange their own gas transportation and supply. This flexibility may help participants to manage risks.

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 may not affect the price of gas that is actively traded between participants.

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.

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

The introduction of firm physical capacity rights might 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.

Trading between the DWGM and interconnected pipelines

This option is more consistent with the contract carriage arrangements that exist outside the DTS and therefore may reduce transaction costs from trading between markets.

Being able to access firm capacity rights will give participants certainty that they may transport gas into or out of the DTS.

Promoting competition in upstream and downstream markets

The sup-options that retain the DWGM give participants flexibility as to whether gas and capacity is obtained through the DWGM scheduling process or bilaterally. This may support competition as gas users can choose the arrangement that best suits their business needs.

7 Other issues and options identified by stakeholders

Through the latest round of consultation in this review, stakeholders have raised a number of other potential issues in the DWGM, and in some cases options to address them.

It appears that the issues identified are not directly or substantially related to those identified in our terms of reference and throughout this review, as outlined in our assessment framework in section 1.2. Most of these potential issues concern relatively specific and detailed aspects of the DWGM design, and therefore may be resolved were significant reform to the DWMG implemented. Nevertheless, actions to address these issues might be consistent with the long term interests of consumers, either:

- if many of the core elements of the DWGM are retained (and hence the issues are not addressed by more substantial reform), or
- during any transitional period prior to substantial market redesign taking effect.

This chapter outlines six potential issues raised by stakeholders and possible options to address them, identified by either the stakeholders themselves or the Commission. The Commission welcomes stakeholders' views on:

- whether or not the issues identified are directly or substantially related to those identified in our terms of reference and throughout this review
- regardless, whether there is merit addressing the issues, and whether the options proposed or alternative options are appropriate, with consideration of:
  - the costs and benefits of any reform
  - whether these issues are otherwise addressed through options discussed in chapters 3 to 6
- whether any of the options should implemented in the near term by industry or AEMO, or through a rule change proposal submitted to the AEMC.

7.1 Bidding behaviour during times of constraints

In determining an operating schedule, the market clearing engine schedules the lowest price combination of offers to meet demand, taking into account constraints.

When a number of participants offer or bid their gas at the same price (such as the market price floor or cap), in the event of a constraint the market clearing engine prioritises those participants with relevant AMDQ, and constrains off market participants without relevant AMDQ.

Given that the market participants are offering or bidding gas at the same price, the market clearing engine currently has no means to assess the most appropriate offers without AMDQ that should be constrained off in order to promote an efficient schedule. It therefore pro-rates the quantity of gas offered by non-AMDQ holders. [110]

Given these market arrangements, market participants are incentivised to manage constraints by offering or bidding quantities well above their actual requirements at the market floor price or market price cap, knowing that the market clearing engine will pro-rate this quantity down due to the constraint. This approach maximises the amount of their gas that is scheduled.

Some stakeholders consider this to be an issue because:

- it incentivises participants to make bids or offers for quantities of gas that are beyond what they intend to flow that day (at a price not reflective of their underlying willingness to buy or sell gas)
- pro-rating causes an arbitrary scheduling outcome, rather than one that maximises scheduling efficiency.

A potential solution to this issue includes decreasing the market floor price (to a negative number) and/or increasing the market price cap. This may discourage market participants from bidding/offering at the cap/floor price, because of the increased negative outcome were market participants to receive extreme prices having not bid/offered reflective of their underlying willingness to buy/sell. However if market participants are confident that the market price will not be very high or low, their behaviour may not change and they may continue to offer/bid as much gas as possible at the revised market cap/floor. Careful consideration would also have to be given to the wider implications of change the market floor price and market price cap.

7.2 Review the market clearing engine algorithm and inputs

As noted above, the market clearing engine creates an operating schedule that reflects the least priced combination of gas to meet demand, given constraints. The engine runs an algorithm to determine the operating schedule, which takes into account a number of inputs such as constraint equations which reflect physical constraints on the system.

Some stakeholders have questioned whether the algorithm appropriately schedules gas given its inputs. The Commission understands that the algorithm has not been significantly updated since the introduction of the DWMG in the late 1990s and is therefore based on the technology and computing power at that time.

Stakeholders have also questioned the appropriateness of the constraint equations and other inputs to the algorithm. For example, if the constraints are too narrowly defined (conservative) then:

110 Should there be too little capacity to schedule all AMDQ holders (such as due to equipment failure) the market clearing engine will also constrain off market participants with AMDQ once all market participants without AMDQ have been constrained off. AMDQ holders are also pro-rated (once all non-AMDQ holders have been constrained off).

- the lowest cost combination of gas that could actually have been scheduled would not be scheduled - an inefficient outcome
- more out of merit order gas would be scheduled, creating greater uplift payments for market participants.

On the other hand, if constraints are too widely defined it may result in gas being unable to flow consistent with the operating schedule.

Stakeholders have suggested that the market clearing engine algorithm and inputs could be reviewed to improve the efficiency of scheduling and reduce risks for market participants. However, at this stage the Commission has received no evidence that the market clearing engine algorithm or inputs need to be adjusted. The purpose of the review of the market clearing engine would be to determine this.

Reviewing and changing the market clearing engine's algorithm and inputs may be expensive, challenging and risky, and would likely require expert engineering and IT advice.

7.3 Publication of linepack adjustments

Currently AEMO manages deviations to a DWGM schedule by scheduling more or less gas in the next schedule to make up for any deviations, and indirectly passing the cost/revenue associated with this action to the market participants which deviated. This seeks to adjust the level of linepack in the system back to a level deemed appropriate by AEMO.

Some stakeholders have suggested that if they had access to (nearer real time) supply and demand information in the DWGM, for example when residential load is increasing, or information about AEMO's intentions to buy or sell gas to maintain system balance, they could adjust their bids and offers for the next schedule accordingly. Alternatively, the existing information published as raw data could be made more user-friendly for market participants, reducing the time, effort and expertise required to interpret it.

7.4 More timely market data

Currently, customer consumption and allocation information[111] is provided to market participants three business days after the gas day, and is progressively updated as more accurate data becomes available.

Some stakeholders consider that it would be beneficial to receive this information in a more timely manner.

111 Allocation information is the shipper's metering data that tracks gas flows into and out of the system, and accordingly the shipper's liability.

Customer consumption information is used by participants to determine and monitor their physical and financial positions. It is also used to forecast future customer consumption. These risk management activities could be enhanced by receiving the information sooner.

While it is generally beneficial to improve the quality and timeliness of information provided to the market, providing this information sooner than three days may impose costs. Furthermore, without potentially significant upgrades to IT and metering infrastructure the information that can be provided to the market within shorter timeframes may be inaccurate, because it is based on aggregated data from which the published information would be calculated using assumptions.

7.5 Recentralise market demand forecasts

Historically, AEMO was responsible for the mass market forecasts for non-controllable withdrawals. Since 2007, DWGM market participants with non-controllable withdrawals (such as retailers) provide their demand forecasts to AEMO to feed into the scheduling process. AEMO also makes a forecast of demand, and, in some circumstances, partially overrides market participants' collective forecast.[112]

Some stakeholders have suggested that AEMO (alone) should once again be responsible for determining a mass market demand forecast because:

- AEMO may make more accurate forecasts, as the forecast would be a whole of market forecast instead of the sum of individual forecasts, avoiding compounding errors
- it could lower barriers to entry for new entrants, as they would no longer need to undertake their own forecasting. Potentially, this would also impact on their exposure to surprise uplift and deviation if those forecasts were wrong.

Alternatively, market participants could choose for AEMO to undertake their mass market forecasts on their behalf, although this may serve to diminish the benefits listed above.

However, participants would likely be creating their own forecasts anyway in order to manage risks. Furthermore, participants may be better at knowing their customer usage and currently have an incentive to develop accurate forecasts to avoid surprise uplift and deviation charges.

7.6 Descheduled gas

Under the current arrangements, participants that have been scheduled to inject or withdraw into the DWGM can be descheduled throughout the day at subsequent schedules. This may occur:

112 AEMO, *Demand override methodology*, 16 July 2013.

- during times of constraint, and is more likely to affect market participants that do not hold sufficient AMDQ, as these market participants are constrained off first in the event of tied offers/bids
- where there is a change in the bids and offers in the market and the participant is no longer in merit order.

Stakeholders have raised concerns with being descheduled due to a constraint, but not being descheduled due to no longer being competitive due to price. As market participants are required to pay imbalance payments for the descheduled amount of gas at the new market price, an increase in the market price combined with a deschedule of gas could result in a financial loss for the market participant.

While this issue appears theoretically possible, the Commission questions its likelihood and materiality in practice, and in this regard welcomes empirical evidence.

Some stakeholders also noted that being descheduled is an issue where there is an underlying contract outside of the DWGM they are required to meet (for example, export to Culcairn), and the participant has started to flow gas in accordance with the first schedule of the day.

Two solutions have been put forward to address this problem.

The first proposal is to firm up the price paid (or received) by descheduled participants. If a participant is descheduled due to congestion, it would pay (or receive) the original market price for the imbalance payment, instead of the new market price. This would prevent a financial loss (or gain) for participants. Careful consideration would have to be given to distinguish between those market participants descheduled due to congestion and those descheduled due to no longer being in merit order.

However, this proposal may result in imbalanced settlement outcomes, as the participants descheduled due to constraints may have paid or received more or less than the market price. These costs or revenues could be socialised between all market participants.

The second proposal is to firm up the capacity of already scheduled participants. That is, in a reschedule, participants that were not in the previous schedule would be constrained off before participants from the previous schedule, even if the participant from the previous schedule does not have AMDQ. This would appear to reduce the value of AMDQ, may impact scheduling efficiency and create perverse incentives for market participants to "lock in" a price and quantity of gas at the start of the day.

8 Combinations of options

This paper has raised a number of different ways in which the existing DWGM could be improved to address the issues identified in the terms of reference for this review and by the Commission.

This chapter provides stakeholders with some guidance on how different options could be combined to collectively address the issues identified and provides some illustrative examples in this regard.

8.1 Assessment framework

As discussed in section 1.2, in this review the Commission has been asked to make recommendations to achieve the following attributes:

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

While none of the options in this paper individually addresses all of the issues with the DWGM, a suitable package might combine options that address each of these issues. In general, throughout this paper:

- options that facilitate financial or physical trading of gas (chapters 3 and 4 respectively) primarily aim to improve the ability for participants to manage price and volume risk
- options that improve AMDQ (chapter 5) or provide firmer (or fully firm) capacity rights (chapter 6) intend to provide better signals for investment in pipelines.

Some of the individual options may also help to improve trading between the DWGM and interconnected pipelines, or promote competition in upstream or downstream markets. These specifics are noted throughout the paper in the assessment of each option.

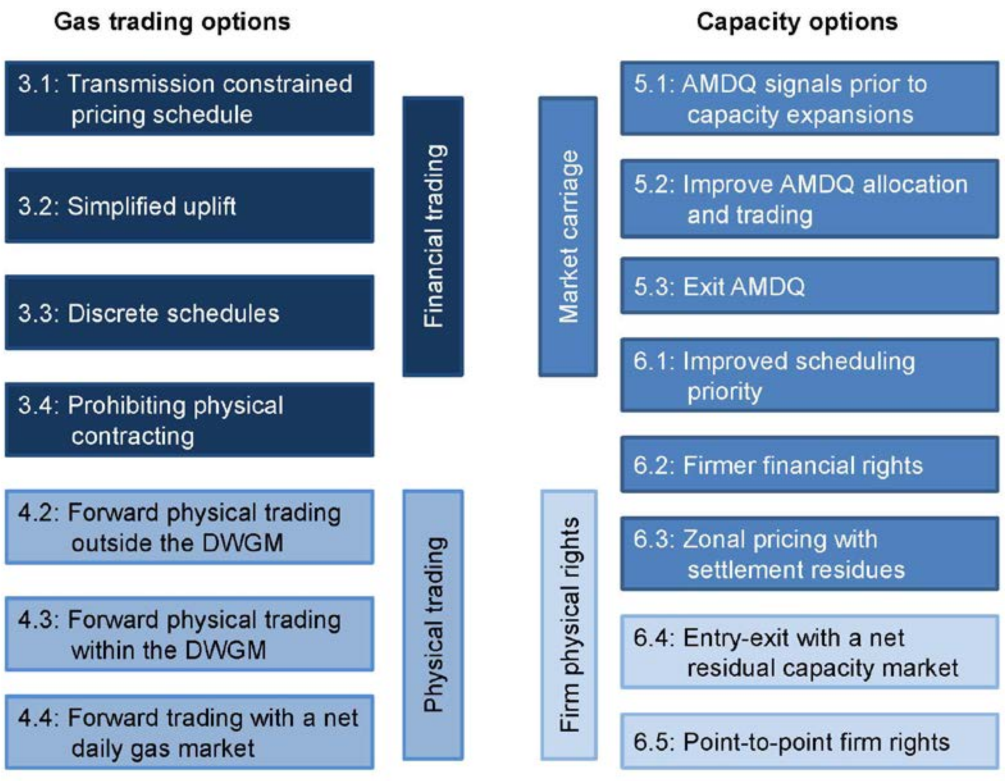
8.2 Market design elements

As identified in section 1.4, the two key market design elements for gas market reform are:

- arrangements for gas trading
- capacity allocation (access).

The diagram below summarises the options presented in chapter 3 to 6 of this paper, organised by those that primarily alter the arrangements for gas trading (chapters 3 and 4) and those which address the allocation of capacity (chapters 5 and 6).

Figure 8.1: Market reform options presented in this paper



In order to meet the COAG Energy Council's vision and align the Victorian gas market more fully with the arrangements across the east coast, it may be necessary to implement options that address both gas trading and capacity allocation and investment. That is, options from chapters 3 and 4 which primarily alter the arrangements for gas trading may need to be combined with options from chapters 5 and 6 which primarily address the allocation of capacity.

The draft model addresses both gas trading and capacity allocation and investment by replacing the DWGM daily gross pool market with continuous forward trading (either bilaterally or through an exchange), so participants can trade a range of gas products to suit their needs at any time. This is coupled with replacing the DWGM's daily implicit allocation of capacity with explicit firm capacity rights, provided on an entry and/or exit basis to the DTS.

While the draft model provides a comprehensive package of reforms for the DWGM, other packages may provide benefits with less disruption to the existing market participants, at lower cost, and with lower implementation risks. One possibility for reform could be to implement incremental market changes which are broadly compatible with the core features of the existing DWGM in the first instance. If benefits are not sufficiently realised (or other specific conditions are met) more significant market reforms could be investigated, such as the draft model, prohibiting physical gas trading (section 3.4), or introducing point-to-point contract carriage to the DWGM (section 6.5).

The Commission therefore welcomes feedback on the benefits of potential packages of reform compared to the costs and risks of implementation. We are also interested in stakeholder views on the appropriateness of implementing an incremental package of reforms in the first instance which largely retain the core features of the existing DWGM.

The remainder of this section does not identify "packages" of options for stakeholder feedback. Instead it provides some guidance to stakeholders on which options might be compatible with each other and provides some non-exhaustive examples of how the options could, or could not, be combined. The Commission welcomes feedback on this assessment.

8.2.1 Combining options to improve risk management

As noted above, chapters 3 and 4 contain options which primarily seek to improve the ability of market participants to manage price and volume risk.

Some of the options within these chapters could be combined in order to provide market participants with a range of measures to manage risk, or because they individually address multiple barriers that may currently be limiting the ability of market participants to effectively manage their risk. For example:

- the development of both a liquid financial derivatives market and a liquid physical gas market (chapters 3 and 4 respectively) would provide market participants options regarding how they manage their risk. It may therefore be beneficial for a gas market design to include or facilitate both of these elements

- introducing a transmission constrained pricing schedule (section 3.1), discrete schedules (section 3.3) and prohibiting physical trade outside of the DWGM (section 3.4) may address different barriers to developing a financial derivatives market. Conceivably, implementing one but not others may not address all the barriers identified, and so be less effective than implementing all together.

On the other hand, there are several options that could not be workably combined. For example, it would not make sense to simplify the uplift charges (section 3.2) as well as implementing a single pricing schedule taking into account transmission constraints as this would abolish the uplift charges (section 3.1).

The Commission considers that the majority of the options in these chapters represent relatively modest changes to the DWGM (in comparison to the draft model) which allow for core design features of the existing DWGM to be retained. The exceptions to this are:

- prohibiting market participants from entering into bilateral trades outside of the DWGM (section 3.4), which might result in significant changes to the market's structure, and may also require significant transitional issues to be addressed
- AEMO retaining balancing responsibility through a net pool market (section 4.4) and opposed to the gross pool market of the current DWGM.

8.2.2 Combining options to provide better signals for pipeline investment

There appears to be one key limitation when considering possible combinations of options allocating capacity. It does not appear to be possible to have open access to physical pipeline capacity (market carriage) at the same place or time as physically firm access rights. That is, there can only be one mechanism to allocate a particular unit (in time and by location) of physical capacity.

This limitation is observed in the current market design. The DWGM is a market carriage framework which allocates physical capacity through a combined commodity and capacity market. Consequently, AMDQ may only provide non-firm physical capacity rights. The limitation is also observed in the draft model where firm physical capacity rights would be provided on an entry and exit basis, with a separate commodity market operating completely distinct from the allocation of capacity.

That said, some of the options in this paper provide a hybrid approach and avoid this limitation to some degree. For example:

- In the option outlined in section 6.4, firm capacity rights may be secured by participants, but any spare or unused capacity may then be allocated to participants through a market carriage process.
- In the option outlined in section 6.5, sub-option 1 applies firm capacity rights in some locations on the DTS and market carriage in others. Sub-options 1 and 2 allow AEMO to secure firm capacity rights and then re-allocate that capacity to DWGM participants through a market carriage process.

While there can only be one way to allocate a particular unit of physical capacity, there is no restriction on retaining the physical allocation of capacity through a market carriage approach while introducing financial capacity rights, because they are not mutually exclusive. Therefore the options to provide firmer financial rights (section 6.2) or zonal pricing with settlement residues (section 6.3) could be combined with any of the options that seek to improve the existing market carriage model.

As with options to improve the ability of market participants to manage their risk, the majority of options in chapters 5 and 6 allow, in broad terms, for the core design features of the existing DWGM to be retained. The exceptions to this appear to be those options which create physical firm capacity rights (sections 6.4 and section 6.5) which, for the reasons discussed above, are not compatible with market carriage allocation of pipeline capacity throughout the DTS.

8.2.3 Combining options which address the suit of issues identified

In general, the capacity options that are related to or retain market carriage arrangements are compatible with the gas trading options that retain the core features of the existing DWGM. Given that the majority of options considered in this paper allow, in broad terms, for the retention of the core features of the DWGM, there are a significant number of possible combinations in this regard.

One particularly natural fit of combining gas trading options with capacity allocation option is the introduction of bilateral gas trading with a net market for outstanding gas requirements (section 4.4) and an entry-exit firm capacity market with a net market for capacity allocation (section 6.4). If these were combined, participants would bilaterally trade gas and secure firm capacity up to a specific cut-off point in time and make nominations consistent with those trades. A net market would then allocate the spare system capacity and determine gas flows based on bids and offers by participants.

8.3 Summary

As note in section 8.1, the Commission welcomes feedback on all of the options for DWGM market reform put forward in this paper. In particular, the Commission is interested in stakeholder feedback on:

- the benefits of each option – including whether and how each option addresses the stated issues with the DWGM
- issues that may require further thought prior to implementation
- how options could be combined to best address the issues with the DWGM.

Submissions on this discussion paper are due by Thursday 11 May 2017.

Abbreviations

ACCC	Australia Competition and Consumer Commission
ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	authorised maximum daily quantity
AMDQ cc	AMDQ credit certificates
AMIQ	authorised maximum interval quantity
ASX	Australian Securities Exchange
COAG	Council of Australian Governments
Commission	See AEMC
DTS	declared transmission system
DWGM	declared wholesale gas market
GMRG	Gas Market Reform Group
GPG	gas powered generator
GSA	gas supply agreement
GTA	gas transportation agreement
GSH	gas supply hub
LNG	liquified natural gas
MDQ	maximum daily quantity
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