Australian Energy Market Commission

REVIEW

DISCUSSION PAPER

Review of the Victorian Declared Wholesale Gas Market

3 March 2016

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Discussion Paper

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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.

Summary

This discussion paper has been published to provide stakeholders with an opportunity to contribute to the further development of the Australian Energy Market Commission's (AEMC or Commission) draft recommendations for a new Southern Hub gas trading model, accompanied by an entry-exit system for capacity allocation, in Victoria.

With a view to the longer term, the AEMC developed a package of reform for the Victorian declared wholesale gas market (DWGM) and associated market carriage arrangements which govern access to the Victorian declared transmission system (DTS). These reforms were set out in the Draft Report for the Review of the Victorian Declared Wholesale Gas Market, presented to the Council of Australian Governments (COAG) Energy Council on 4 December 2015. They involve:

- transitioning from the DWGM where trading and balancing occurs on a mandatory, operator led-basis, to the new 'Southern Hub' model where trading and balancing would occur on a voluntary, continuous basis and where the hub operator plays only a residual role; and
- supporting this new form of trading with a system of entry and exit rights which, collectively, contribute to gas being able to be traded independently of its location in the system.

In developing this package of reform, the AEMC has undertaken its own analysis, considered the outcomes of a number of previous reviews and has had regard to the views of a range of stakeholders in submissions.

Previous reviews of the Victorian gas market have highlighted a number of issues with different elements of the Victorian market design and a range of possible solutions to the issues have been considered.[1] In September 2015, the AEMC published a discussion paper which provided stakeholders with the opportunity to comment on many of the solutions previously proposed.[2] The discussion paper presented a range of reform options, from smaller incremental changes to transitioning from Victoria's market carriage model to a contract carriage model for managing capacity allocation. Based on submissions, and having undertaken its own analysis, the Commission has presented a package of reforms to the COAG Energy Council which aims to deliver the Energy Council's Vision and achieve the best outcomes for Victorian consumers, consistent with the National Gas Objective (NGO).

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

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

The proposed changes are anticipated to fundamentally improve the outcomes of the Victorian gas market by providing participants with greater flexibility to physically trade gas in the market, and establishing the preconditions required for financial risk management products to develop. The changes will also create market-driven signals for investment in the pipeline system, a feature currently absent from the Victorian DWGM.

Importantly, the proposed reforms will not undermine elements of the Victorian market that have been beneficial, both in terms of stimulating a competitive retail gas market and safeguarding the security of gas supply for Victorian customers, as to do so would not allow the reform package to meet the NGO.

Trading at the "virtual hub" formed by the DTS will provide new entrant retailers and large industrial users with greater flexibility in how they buy and sell gas than the current mandatory gross pool arrangements in the DWGM. Retailers and large users will be able to enter into trades with any other party, irrespective of their location on the DTS, for any period of time. This trading can occur either bilaterally or through the exchange, which will represent a low cost, anonymous and transparent trading mechanism with no counter-party risk.

While new entrant retailers can currently obtain gas at the prevailing daily market price in the DWGM, if they wish to hedge this risk they have to enter into a physical trade with a producer (for example, at Longford). The recommended new market design would provide more options to new entrants to hedge price risks through either physical or financial trades at the virtual hub, with a wider range of counter-parties. This optionality lowers barriers to entry, supports the growth of smaller retailers and promotes competition, creating benefits for consumers.

Further, residual balancing arrangements would mean that if a party was not fully contracted, the system operator would obtain gas on its behalf and charge the party for this. This will ensure that network pressures are maintained within safe operational limits and that gas continues to flow to consumers, as well as providing a fall-back option for participants to purchase gas.

The proposed reforms to the Victorian gas market form part of the AEMC's broader roadmap for the development of the East Coast Gas Market. A Final Report for the Victoria DWGM Review and for the East Coast Wholesale Gas Market and Pipeline Frameworks Review (East Coast Review) will be delivered to the COAG Energy Council in May. Both reports will provide further detail on the broader East Coast Gas Market reform package, including on the recommendations for a new Southern Hub in Victoria.

This discussion paper has been published to provide stakeholders with an opportunity to contribute to the development of the next layer of detail on the Southern Hub model, leading into the Commission's Final Report. Having regard to the unique physical characteristics of the Victorian DTS, this discussion paper is based around four key themes and focuses on the key design issues relevant to the Southern Hub model which need to be addressed ahead of the Final Report.[3] Specifically, this paper focuses on the following:

- **Managing capacity at the Southern Hub**: Chapter 3 identifies the new functions which would be created by the Southern Hub and discusses the allocation of these roles between APA GasNet and the Australian Energy Market Operator (AEMO), having regard to a number of trade-offs which need to be considered. This chapter also discusses the importance of the process for calculating baseline (and above-baseline) transmission capacity in considering the allocation of roles at the Southern Hub.

- **Capacity allocation mechanisms**: Chapter 4 discusses the mechanisms available for allocating existing baseline capacity at the Southern Hub and for triggering incremental capacity investments. It outlines the general principles behind such allocations, along with the characteristics of existing entry and exit points to the DTS. It then presents the Commission's preliminary view on the most appropriate mechanism for allocating transmission capacity at entry and exit points within the Southern Hub. A discussion on transitioning AMDQ and AMDQ cc concludes this chapter.

- **Capacity pricing and revenue**: Chapter 5 briefly discusses how pipeline services provided under the entry-exit system could fit within the existing regulatory framework for gas pipelines. It then outlines the general process followed when setting regulated capacity tariffs in entry-exit systems. It highlights the factors that need to be considered when designing tariffs for entry and exit points and considers how this could be done at the Southern Hub.

- **Balancing**: Chapter 6 discusses balancing at the Southern Hub. It sets out principles for balancing arrangements, along with the characteristics of the DTS and the trade-offs that need to be considered in respect of the balancing period, financial incentives and procurement of balancing gas. Two models based on different European approaches are considered: continuous market-based balancing and fixed period market based balancing.

As part of the stakeholder consultation process, the AEMC is also consulting on a number of issues relevant to the broader East Coast Gas Market reforms, with particular focus on the pipeline capacity market recommendations. These matters are considered in a separate discussion paper also published today and available on the AEMC website.

We are also seeking more feedback on the costs and benefits to businesses of transitioning to the Southern Hub gas trading model. The further detail provided in this paper should help market participants to provide this feedback. In the lead up to the Final Report in May, the AEMC will be undertaking more work to better

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3 Other matters which are integral to the design of the Southern Hub but which are not discussed in this paper will be considered further in the Final Report. Additional areas include congestion management tools, gas trading exchange arrangements and the ongoing governance and implementation framework.

understand the costs and benefits associated with different elements of the reform package.

Feedback

Feedback from stakeholders will be used to inform the Commission's final recommendations for the Victorian DWGM review which will be presented to the COAG Energy Council in mid-2016. We welcome responses on any of the matters outlined in this discussion paper. However, in light of the tight timeframes for consultation, the Commission has set out a few questions intended to help focus submissions. These are set out in Chapter 1.

The closing date for submissions is **29 March 2016**.

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1 Introduction

On 4 December 2015, the Australian Energy Market Commission (AEMC or Commission) published a Draft Report for the Review of the Victorian Declared Wholesale Gas Market (DWGM).[4] With a view to the longer term, the Commission proposed a package of reform for the DWGM and associated market carriage arrangements which govern access to the Victorian declared transmission system (DTS). The Commission's draft recommendations are to retain the virtual hub definition in Victoria but to transition the trading arrangements to a system of voluntary and continuous exchange-based trading with market-based balancing.

The AEMC's draft recommendations are part of an integrated package of reform of the east coast and Victorian gas markets. Developed with regard to the Council of Australian Governments (COAG) Energy Council's Vision and Gas Market Development Plan, the integrated reform package supports three key outcomes:

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

Once in place, the AEMC's proposed reforms will form a strong foundation for facilitated gas markets and transportation arrangements in eastern and southern Australia to promote the National Gas Objective (NGO) and achieve the Energy Council's Vision.

The Final Reports for the East Coast Wholesale Gas Market and Pipeline Frameworks Review (East Coast Review) and the Victorian DWGM Review will be delivered to the Energy Council in May 2016.

This discussion paper relates specifically to the draft recommendations set out in the Draft Report for Victorian DWGM Review.

1.1 Purpose of this discussion paper

To progress the development of the Southern Hub model and to provide stakeholders with the opportunity to provide more focussed feedback leading into the Final Report for the Victorian DWGM Review, the AEMC has set out its initial thoughts on possible

4 At its December 2014 meeting, the Council of Australian Governments (COAG) Energy Council released its Vision for the Australian gas market. It subsequently asked the AEMC to review the role and objectives of the facilitated gas markets currently in operation in eastern Australia (the East Coast Review) and to undertake a separate, detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the Victorian DWGM (Victorian DWGM Review).

design options for the capacity allocation and gas balancing regimes at the Southern Hub.

The realisation of a liquid trading hub in Victoria requires, among other things, the development of an entry-exit system capable of allocating capacity in a manner which promotes competition and optimises the use of the network. The capacity regime must also provide for the market to signal the need for new capacity in a manner which promotes timely and efficient pipeline investment decisions.

Achieving a liquid Southern Hub also requires the development of a gas balancing regime which encourages and facilitates gas trading at the Southern Hub, and supports competition and efficient operation of the network. The gas balancing arrangements are of particular importance for new market entrants.

Specifically, this discussion paper considers the design of the entry-exit system for capacity allocation at the proposed Southern Hub, including options for mechanisms to allocate existing capacity and approaches to signalling the need for new capacity. It then considers the design of arrangements to support gas balancing within the proposed Southern Hub, including options for the balancing period and balancing incentives.

The remainder of this paper is structured as follows:

- Chapter 2 summarises the Commission's draft recommendation for the introduction of a Southern Hub trading model with an entry-exit system for capacity allocation, in Victoria. It places these reforms in the context of the evolving east coast gas market and provides an overview of the Commission's review process to date, including the work that has been done to develop the proposed reform package for the Victorian Gas market.

- Chapter 3 considers capacity management at the Southern Hub. It identifies the new functions which would be created by the Southern Hub and discusses the allocation of these roles between APA GasNet (APA) and the Australian Energy Market Operator (AEMO), having regard to a number of trade-offs which need to be considered. This chapter also discusses the importance of the process for calculating baseline (and above-baseline) transmission capacity in considering the allocation of roles at the Southern Hub.

- Chapter 4 discusses the mechanisms available for allocating existing baseline capacity at the Southern Hub and for triggering incremental capacity investments. It outlines the general principles behind such allocations, along with the characteristics of existing entry and exit points to the DTS. It then presents the Commission's preliminary view on the most appropriate mechanism for allocating transmission capacity at entry and exit points within the Southern Hub. A discussion on transitioning AMDQ and AMDQ cc concludes this chapter.

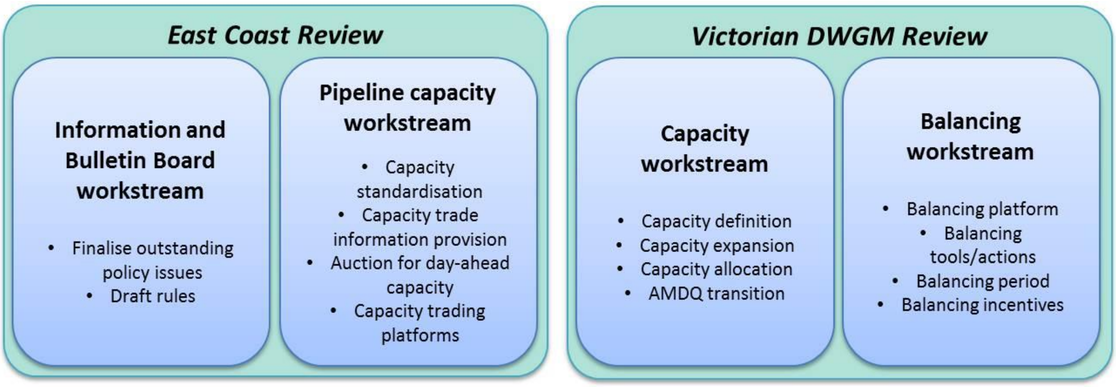
- Chapter 5 considers a number of matters relevant to the revenue and pricing arrangements under the Southern Hub model. It outlines the existing framework for the regulation of pipeline services and considers how the new market design would fit within this framework. It then outlines the general process for setting tariffs in entry-exit systems and compares this to the process currently used to set tariffs in the DTS.

- Chapter 6 discusses balancing at the Southern Hub. It sets out principles for balancing arrangements, the characteristics of the DTS and the trade-offs that need to be considered in respect of the balancing period, financial incentives and procurement of balancing gas. Two models based on different European approaches are considered: continuous market-based balancing and fixed period market based balancing.

1.2 Next steps in the development of our final recommendations

The Final Report's for the East Coast Review and the Victorian DWGM Review will be delivered to the Energy Council in May 2016. In order to provide stakeholders with the opportunity to contribute to further development of the reform package ahead of May, the AEMC has developed a work program which focuses on key questions and design issues that need to be addressed ahead of presenting the final recommendations to the Energy Council. To this end, the AEMC will be progressing four broad workstreams.[5] These are illustrated in Figure 1.1 below.

Figure 1.1 Overview of gas review workstreams



This discussion paper relates to the capacity and gas balancing workstreams specific to the Victorian DWGM Review.

Feedback from stakeholders through the consultation process, as well as input from the Advisory Group,[6] will inform the Commission's recommendations in the Final Reports. The Commission will also continue to work closely with AEMO and the

5 Further information on the AEMC's consultation program for the East Coast and DWGM Gas Reviews is available on the East Coast Wholesale Gas Market and Pipeline Frameworks Review project page at www.aemc.gov.au.

6 As required by the terms of reference for the East Coast review, the Commission has established an Advisory Group that operates across both the East Coast and DWGM reviews. The Advisory Group includes representatives of AEMO, pipeline owners, retailers, producers, large consumers and consumer groups and provides strategic advice and expertise to the Commission. It meets periodically and is chaired by John Pierce, AEMC Chairman.

Australian Energy Regulator (AER) throughout the remainder of the reviews to draw on their operational and regulatory expertise as we continue to develop our advice.

1.3 Responding to this paper

The Commission welcomes submissions on any of the issues raised in this discussion paper. In particular, we are interested in stakeholders' views on the following points:

Overall

- Recognising that the detailed design of the Southern Hub is still to be determined, what are likely to be the key benefits, risks and costs to your business of transitioning to the Southern Hub model? Estimates on the magnitude of these benefits and costs are welcomed.

Chapter 3

- Given existing allocation of roles between pipeline owner and system operator in the DTS and DWGM, whether the proposed allocation of system operation functions at the Southern Hub is appropriate and likely to achieve the optimal balance between efficient use and efficient operation of the system.

Chapter 4

- Whether integrated auctions are the most appropriate mechanism to allocate existing (and trigger new) baseline capacity at production entry points, interconnection entry/exit points and storage entry/exit points. What are the likely challenges in developing and applying an auction mechanism in this context?

- Whether an auction mechanism, combined with a bilateral planning process between APA and directly connected customers, is the most appropriate mechanism to allocate existing (and trigger new) baseline capacity for exit points relating to large customers directly connected to the DTS. What are the likely challenges in developing and applying these mechanisms?

- Whether automatic allocation of capacity, combined with a bilateral planning process between APA and distributors/retailers, is the most appropriate mechanism to allocate existing (and trigger new) baseline capacity for distribution exit points. What are the likely challenges in developing and applying these mechanisms?

- Having regard to the Commission's preliminary view on options for allocating capacity, how the matter of transitioning the existing, albeit limited, benefits afforded to market participants holding authorised maximum daily quantity (AMDQ) and AMDQ credit certificates (AMDQ cc) could be addressed under the proposed Southern Hub.

Chapter 5

- Whether the pricing and revenue arrangements required by an entry-exit system can be accommodated within the existing framework for the regulation of gas pipelines, or whether changes to that framework need to be considered.

Chapter 6

- Whether a continuous balancing period, similar to the Dutch system, could be implemented at the Southern Hub. Consideration should be given to the costs and likely benefits of this approach.

- Whether the procurement of balancing gas could occur through the purchase of spot products on the Southern Hub exchange at market start, or whether a separate balancing platform is required.

- In the instance a fixed balancing period was considered appropriate, what an appropriate timeframe would be.

- Stakeholders views on the role of AEMO as residual balancer and how it should perform this function.

The closing date for submissions is **Thursday 29 March 2015**.

Submissions should quote project number "GPR0002" and may be lodged online at www.aemc.gov.au or by mail to: Australian Energy Market Commission PO Box A2449 Sydney South NSW 1235.

2 Achieving the vision for the Victorian gas market

2.1 Overview of the proposed Southern Hub

The Commission's recommended changes to the Victorian DWGM seek to develop a new "Southern Hub" for trading gas, and are focussed on two key areas:

- **Exchange-based trading**: transitioning from the DWGM - where trading and balancing occurs on a mandatory, operator led-basis - to a new model where trading would occur on a voluntary, continuous basis but underpinned by a mandatory residual balancing mechanism. A key feature of the Southern Hub would be the introduction of exchange trading, making the trading mechanism consistent with the Northern Hub at Wallumbilla in Queensland.

- **Entry-exit capacity allocation**: to support this new form of trading, transitioning the market carriage model and associated limited pipeline transportation rights to a system of entry and exit rights for capacity allocation. This would allow network users to book firm transportation capacity rights independently at each entry and exit point to the DTS. Collectively, these enhancements would contribute to gas being able to be traded independently of its location in the system.

The Southern Hub trading model and complementary entry-exit system would transform the way in which market participants' access and trade in the market, and the way in which pipeline investment is signalled. Specifically, the enhanced market framework should:

- minimise overall system balancing costs and maintain the existing high level of system security in Victoria by introducing a continuous market-based balancing mechanism that allows shippers to determine when and how to take balancing actions;

- provide market participants with the opportunity to trade gas independently of its location in the system and with any other participant in the market on a continuous basis, allowing them to better manage their gas portfolios in response to their short and long term needs;

- support the development of a meaningful reference price reflective of underlying supply and demand conditions that usefully aids commercial investment decisions and the development of financial products;

- make the trading arrangements largely consistent with the Northern Hub, reducing the administrative costs of market participants operating across the east coast;

- provide market participants with the ability to secure firm access rights to transportation capacity at any entry and/or exit point on the DTS, reducing the risks of being exposed to unmanageable congestion costs or not being scheduled;

- eliminate transaction costs for market participants wishing to ship their own gas across the DTS, as participating in the DWGM gross pool will no longer be mandatory; and

- contribute to decision-making about future pipeline investment by creating signals driven by market participant choices to book capacity at entry and/or exit points on the DTS.

This differs considerably from the existing arrangements which are much less flexible, mandating participants use the market by submitting bids and offers for all gas injections and withdrawals from the system even if they are in balance. It would also change the current market pricing mechanism and the way that pipeline capacity is allocated.

The introduction of exchange-based trading would provide participants with greater flexibility in how they buy and sell gas. Trading at the "virtual hub" formed by the DTS will provide new entrant retailers and large industrial users with greater flexibility in how they buy and sell gas than the current reverse auction mechanism in the DWGM. Retailers and large users will be able to enter into trades with any other party, irrespective of their location on the DTS, for any period of time. This trading can occur either bilaterally or through the exchange, which will represent a low cost, anonymous and transparent trading mechanism with no counter-party risk.

In addition, day-ahead and balance-of-day spot products, and longer forward products, can also be traded on the exchange, creating transparency around future price expectations and allowing them to formulate appropriate strategies to manage risks.[7]

Under the proposed entry-exit system, shippers would be able to secure firm access rights to transportation capacity at any entry and/or exit point on the DTS. Where feasible, market based mechanisms would be used to signal the market's demand, or otherwise, for additional capacity at the relevant entry/exit point. The mechanisms for allocating existing and new capacity at entry and exit points are discussed in Chapter 4.

The increased level of market-led investment over the current arrangements under the Commission's recommended model represents a shifting of risk to parties who are best placed to manage it. However, while the intention is for all investment to be triggered by entry and exit capacity being booked by participants (that is, a market signal), the entire associated cost may not necessarily be met by participants and so some risk might continue to be borne by consumers.

Importantly, the proposed Southern Hub would continue to safeguard the security of gas supply for Victorian consumers through the residual balancing mechanism. In the event that market participants do not balance their injections of gas to, and

7 Price discovery would occur via the exchange initially, with prices struck for exchange traded products being published along with a daily volume-weighted average price. As the market develops, the reference price may be produced and published by a price reporting agency.

withdrawals of gas from, the system through their own trading actions, the system operator will take balancing actions to ensure that network pressures are maintained within safe operational limits, and that gas continues to flow to consumers. This process will consequently also give large users and retailers certainty of delivery for gas purchased at the hub.

Noting this, the new framework has several advantages relative to the current arrangements:

- **Flexibility in buying and selling gas:** Trading at the "virtual hub" formed by the DTS will provide new entrant retailers and large industrial users with greater flexibility in how they buy and sell gas than the current reverse auction mechanism in the DWGM. Retailers and large users will be able to enter into trades with any other party, irrespective of their location on the DTS, for any period of time. This trading can occur either bilaterally or through the exchange, which will represent a low cost, anonymous and transparent trading mechanism with no counter-party risk.

  While new entrant retailers can currently obtain gas at the prevailing daily market price in the DWGM, if they wish to hedge this risk they have to enter into a physical trade with a producer (for example, at Longford). The recommended new market design would provide more options to new entrants to hedge price risks through either physical or financial trades at the virtual hub, with a wider range of counter-parties. This optionality lowers barriers to entry and promotes competition, creating benefits for consumers.

  Further, residual balancing arrangements would mean that if a party was not fully contracted, the market operator would obtain gas on its behalf and charge the party for this. This ensures the certainty of delivery to consumers, as well as providing a fall-back option for participants to purchase gas.

- **Transparent and meaningful gas price:** The emergence of a meaningful reference price through the exchange and price reporting of bilateral trades can provide signals to drive the efficient use of gas in the short-term and promote efficient levels of investment in the long-term. A credible market price can be referenced in bilateral contracts, making contracting easier and less costly. Using the market price would remove the need for customers to establish their own price expectations and give them confidence that the price they are paying reflects underlying supply and demand conditions.

- **Lower transaction costs:** The introduction of exchange based trading provides an opportunity to harmonise trading arrangements with those in place at Wallumbilla. For example, introducing common gas day start times,[8] back-end

8 On 19 November 2015, the AEMC received a rule change request from the COAG Energy Council to amend the NGR to align the gas day starting time in the Short Term Trading Market (STTM) in Adelaide, Sydney and Brisbane and the Wallumbilla Gas Supply Hub (GSH) with the current 6am gas day start time in the DWGM. The AEMC published a consultation paper for this rule change on 3 March 2016. Further information is available on the AEMC website.

systems, registration, prudentials, settlement and training where possible. This should lower transaction costs and complexity for large users and retailers operating across multiple markets, and thereby encourage greater participation.

- **Allocation of capacity rights:** The recommended arrangements would allow market participants to drive network investment by purchasing long term entry and exit capacity rights. However, a range of long and short term rights would be available and would be allocated through simple, non-discriminatory mechanisms, such as auctions. The secondary trading of rights would also provide a way for new entrants to obtain rights, and parties with surplus rights to sell them.

Overall, the recommendations will help to support the development of a liquid wholesale gas market in Victoria, providing participants with greater flexibility when buying and selling gas, and consumers with greater transparency around the demand and supply conditions underlying the gas price. It will also support investment in the DTS responding to market signals and being delivered to an efficient size, in the right location and on time.

These recommendations would provide a more robust gas market framework in Victoria, whatever the future. It also makes the gas trading arrangements broadly consistent across the east coast, reducing costs associated with registration, training, prudentials and back-end systems, lower barriers for smaller users. We expect the associated benefits to be greater in a future that involves more rapid changes in supply and demand, dynamic flows across the system and greater trading of gas.

2.2 Context for the review

While the DWGM and market carriage transportation arrangements[9] are generally considered to have been providing an effective gas balancing service and facilitating trading of gas in Victoria historically, the preconditions necessary for the development of financial risk management products do not exist in the DWGM. Wholesale trading risks cannot be managed other than by taking a physical position outside of the market, and this may be deterring new entry and resulting in consumers paying more than is necessary for gas in Victoria.[10]

In addition, the preconditions for market-led investment do not exist, meaning that all consumers bear the risk of inefficient investment, rather than that risk falling on those who are best placed to manage it.

The eastern Australian gas market more broadly is experiencing a period of significant growth and change. In response to the establishment of a liquefied natural gas (LNG)

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

10 See the AEMC's September discussion paper for further information on how market participants currently manage price and volume risk in the DWGM, and the underlying issues that are preventing greater use of derivatives and other risk management tools.

export industry, the east coast gas market is experiencing structural changes to demand and supply dynamics. These changes are expected to significantly affect the Victorian gas market in two ways, namely:

- Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with end users in these states likely to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect, the Eastern Gas Pipeline or the SEA Gas Pipeline.
- Equally, market participants may seek to transport large volumes of gas into Victoria for sale in the DWGM where the LNG export plants are unable to absorb supply due to, for example, an LNG train being taken offline.

With the first LNG cargoes exported from Gladstone in January 2015, the domestic market is already feeling the effects of greater competition for gas. These developments are expected to put upward pressure on gas prices and have resulted in a renewed focus on the efficiency of the gas supply chain. In Victoria, wholesale prices in the first two quarters of 2015 have increased by five and 17 per cent, respectively.[11]

It is therefore critical that the Victorian gas market design is sufficiently flexible to accommodate a range of potential scenarios and that participants are able to actively manage the risks they face. As noted by Ministers at their July 2015 meeting, "the gas market is entering a new era of dynamism, and the imperative was to get the fundamentals right to prepare market participants for new ways of price discovery, trading, investment and risk management".[12]

2.3 The review

This review was requested by the Victorian Government, with the support of the COAG Energy Council, in March 2015. Its purpose has been to consider whether the existing gas market arrangements in Victoria:

- allow participants to effectively manage price and volume risk;
- provide appropriate signals and incentives for investment in and use of pipeline capacity; and
- facilitate the efficient trade of gas to and from adjacent markets.

More broadly, this review has considered whether and to what extent the DWGM continues to promote competition in upstream and downstream markets, in the long term interests of consumers. The terms of reference are available on the AEMC's website.[13]

11 AER Wholesale Statistics, available at: http://www.aer.gov.au/Industry-information/industrystatistics/wholesale

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

13 See www.aemc.gov.au.

The first stage of the Victorian DWGM Review was undertaken jointly with stage 1 of the AEMC's East Coast Gas Market and Pipeline Frameworks Review (East Coast Review).[14]

Stage 1 of the East Coast and Victorian DWGM reviews was completed on 23 July 2015 with the Stage 1 Final Report presented at the Energy Council's July 2015 meeting.[15] The Stage 1 Final Report provided recommended four immediate actions for consideration by the Energy Council to enhance the transparency and efficiency of the market.[16]

The commencement of Stage 2 saw the Victorian DWGM Review split from the East Coast Review and continue as a stand-alone workstream. To progress the debate on gas market development in Victoria, the AEMC published a discussion paper on 10 September 2015.[17]

The purpose of the September discussion paper was to present an appraisal of the existing DWGM arrangements and to set out five high level packages for reform as a way of seeking targeted feedback from stakeholders on the future development of the Victorian gas market.

Each package included one or more policy measures aimed at addressing the issues identified in the appraisal, and each was prepared having regard to the terms of reference for the review and the COAG Energy Council Vision for Australia's future gas market. The five packages are illustrated in the figure below.

14 On 20 February 2015, the COAG Energy Council also requested that the AEMC review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia.

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

16 The four measures which are either complete or in the final stages of implementation included: the introduction of a wholesale gas price index; a rule change to harmonise the gas day; amendments to the NGL to allow any party to propose a DWGM rule change; and addressing additional information gaps through the Enhanced Information for Gas Transmission Pipeline Capacity Trading rule change.

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

Figure 2.1 Packages for reform presented in the September Discussion Paper

Market improvements	Market development		Market reform	
Package A **Targeted measures**	**Package B** **Transmission rights**	**Package C** **Capacity rights**	**Package D** **Entry/Exit model**	**Package E** **Hub & Spoke model**
Targeted transmission rights	Simplified pricing mechanism	Zone-based pricing and capacity rights	Entry/Exit model	GSHs at Longford and Iona and balancing in Melbourne
Trading of AMDQ rights	Transmission rights			
Clearer AMDQ allocation process				
Review planning standard				

The Commission received 11 stakeholder submissions on the discussion paper, most of which were broadly supportive of the AEMC considering a range of market reform packages to meet challenges going forward.[18] However, stakeholders stressed the importance of considering any reform as part of the broader design vision for the east coast gas markets.

Having regard to submissions, the Commission carried out its own detailed assessment of the five packages for reform.[19] In summary, the Commission concluded that the three options focused on incremental improvements and targeted market developments would be unlikely to result in a step-change in trading liquidity or the development of financial products, as envisaged by the Energy Council. In this context, they would be unlikely to achieve the Vision, and therefore unlikely to promote the NGO relative to the status quo.

While the two more significant reform packages (that is, the entry-exit system and hub and spoke model) appeared to have most of the characteristics necessary to form a strong foundation for facilitated gas markets and transportation arrangements, the Commission concluded that the introduction of an entry-exit system would deliver the most comprehensive set of benefits to consumers over the longer term relative to the hub and spoke model, and therefore was most likely to promote the NGO.

In developing this package of reforms the AEMC also drew on a range of previous reviews of the Victorian gas market, including the VENCorp Pricing and Balancing Review undertaken in 2003-04, the Victorian Government's Gas Market Taskforce review of the eastern Australian gas markets completed in 2013 and the AEMC's Gas

18 Submissions on the discussion paper closed on 8 October 2015. These are available on the AEMC's website.

19 The Commission's detailed assessment is set out in Appendix B of the Victorian DWGM Review Draft Report. See: AEMC 2015, *Review of the Victorian Declared Wholesale Gas Market, Draft Report*, 4 December 2015, Sydney, Appendix B.

Market Scoping Study, also completed in 2013.[20] The AEMC has also had regard to work carried out by AEMO and the industry through the Gas Wholesale Consultative Forum.[21]

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

21 AEMO's Gas Wholesale Consultative Forum (GWCF) provides an opportunity for stakeholders to get involved and provide input and ideas into developing and improving the Victorian Gas Wholesale Market and Short Term Trading Markets. The forum facilitates consultation with interested parties including registered participants; government bodies and end user representatives. See AEMO's website for further information: www.aemo.com.au.

3 Managing capacity at the Southern Hub

This chapter considers the arrangement for capacity management at the Southern Hub. First, it summarises the current split of functions in the Victorian gas market and describes the new functions created by the Southern Hub. It sets out the trade-offs that need to be made in deciding the appropriate split of functions between the pipeline owner and system operator, and then sets out the allocation of roles between APA and AEMO under the proposed Southern Hub model.

The chapter also discusses the importance of the process for calculating baseline capacity in considering the arrangements for capacity management at the Southern Hub.

3.1 Institutional roles

Box 3.1 explains the current split of functions between AEMO and APA in the Victorian gas market.

Box 3.1 Current institutional arrangements in Victoria

Under the current gas market arrangements in Victoria, AEMO is responsible for the operation and security of the DTS, which is owned by APA. APA builds and maintains the network, and makes the DTS available to AEMO to operate. In operating the system, AEMO runs the compressors and manages flows across the DTS in accordance with the National Gas Law (NGL), National Gas Rules (NGR) and the terms in the Service Envelope Agreement (SEA) agreed with APA.[22]

The SEA determines, among other things, transportation capacity of the DTS[23] and the obligations of APA and AEMO in relation to the delivery of the agreed capacity.[24]

Unlike contract carriage pipelines, shippers utilising the DTS cannot reserve firm capacity. They may, however, have an AMDQ allocation or AMDQ cc. AMDQ was first allocated at market start and was (and has remained) commensurate

22 Section 91 of the NGL requires the service provider for a DTS to have in place an agreement with AEMO for the control, operation, safety, security and reliability of the DTS.

23 In respect of transportation capacity, AEMO and APA are required to maintain an agreed common system model that is used, among other things, to determine system capacities. This is important for a number of reasons including: determining the impact of planned and unplanned pipeline or plant outages on system capacity; determining the additional pipeline capacity created by pipeline expansions/augmentations for the allocation of AMDQ cc by APA; and providing information to the market and regulators on potential future pipeline constraints for future investment and approval of regulated investment.

24 In respect of each party's obligations, the SEA requires APA to provide AEMO not only the agreed transmission system capacity, but also a range of supporting services. It also requires AEMO to observe good practice in operating the system and not operate facilities in a manner that will materially adversely affect APA's ability to comply with its obligations under the SEA.

with the capacity of the Longford-Melbourne pipeline at that time when it was the primary sole source of gas supply for the DWGM.

As new pipeline capacity has become available, AMDQ cc have been created to provide similar benefits to those arising from AMDQ on the Longford pipeline. The increase in pipeline capacity resulting from an extension or expansion project is agreed between APA (as the pipeline owner) and AEMO (the system and market operator). Once agreement is reached and the new capacity becomes operational, new certificates are created.

AMDQ cc is allocated to market participants for quantities and periods as directed by APA. The allocations reflect the outcome of a competitive tender process APA has managed.[25]In this process, interested market participants have been able to tender for an amount of AMDQ cc for a specified period. Market participants' contract with APA for AMDQ cc, as well as for the payment of the tariffs associated with the use of transmission system.

AEMO also has a key role in operating and administering the gas market in the DWGM. The current arrangements require market participants to bid their injections and withdrawals into the market. It is AEMO's role to manage this bidding and matching process to determine the market clearing price and a schedule of gas flows for each market participant during the gas day (that is, the gas expected to be injected or withdrawn by each market participant at the various points on the system).

AEMO also manages the settlement process, which is conducted ex-post, including calculating charges associated with imbalance (caused by differences in a participant's daily gas injections and withdrawals), deviations (caused by differences between a participant's scheduled and actual behaviour), and ancillary and uplift payments (generated by actions taken to manage constraints at particular locations on the system).

The AEMC's draft recommendations, if implemented, would create a number of new tasks which need to be allocated between AEMO as the system operator, and APA as the pipeline owner. The key tasks in respect of capacity management are defined as follows:[26]

25 The AEMC is currently considering a rule change request in relation to the allocation process for AMDQ and AMDQ cc. Further details of the 'DWGM-AMDQ Allocation' rule change are available on the AEMC's website.

26 This discussion focuses specifically on the allocation of the new tasks related to capacity management under the Southern Hub model. Further work will be carried out ahead of the final report to determine the capabilities required undertake the exchange operator role and, where appropriate, the balancing operator role.

- Calculating the baseline level of capacity at entry and exit points,[27] and allocating this capacity to market participants.

- Identifying whether, and calculating how much, additional capacity above the baseline is available at entry and exit points, and allocating this additional capacity to market participants.

- Operating the system, including managing compressors to convey gas across the system, and managing any congestion that may arise in particular locations.[28]

- Undertaking residual balancing, including buying and selling gas to manage any system balancing issues that may arise.

Under the Southern Hub model, APA as the pipeline owner would continue to build and maintain the network, and to make the DTS available to AEMO to operate. AEMO would retain responsibility for the operation and security of the DTS and, in doing so, would continue to run compressors and manage flows across the DTS in accordance with the relevant statutory and commercial requirements.

The split of the new system operation tasks between AEMO and APA needs to be robust to the evolution of the market and, importantly, needs to be efficient and cost effective given the costs will ultimately be borne by consumers. In this context, the appropriate split between APA as the pipeline owner and AEMO as the current system operator should promote the efficient use and operation of the gas pipeline system. This will occur where the following is achieved:

- Efficiency in the trade-off between investment in new capacity and managing flows to accommodate new demand: when demand for flows onto the system exceeds the available capacity at particular entry/ exit points, there is a trade-off between building new capacity and managing flows such that the additional flows on the system can be accommodated. It may be more efficient in some cases for the system operator to incur greater costs in re-directing flows in order to manage the additional flow than to build new capacity.

- Offering maximum capacity to market participants without incurring excessive constraint management costs: there is a trade-off between maximising the capacity made available to market participants and the costs that may be incurred in managing any resulting constraints.

- Cost efficient system operation: there may be different costs involved with the different tools for managing constraints including: selling gas to reduce flows at a particular location, buying back the transportation capacity or entering into

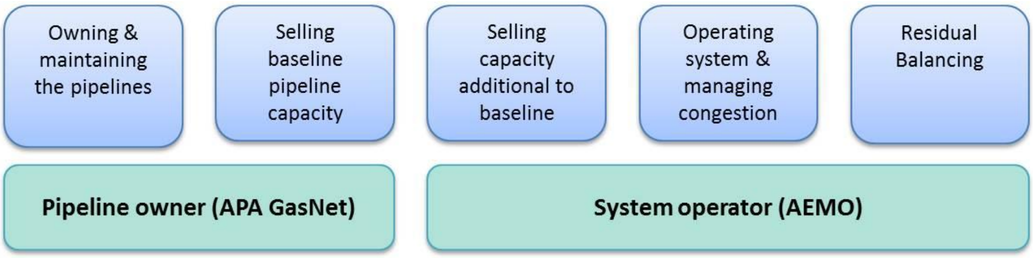
27 While the remainder of this document refers to baseline capacity being calculated for entry and exit 'points', we recognise that in some cases capacity may be calculated on the basis of 'zones', as is the case with distribution networks.

28 Under the Southern Hub, there may be new tools available to manage any congestion on the system, for example, buying back transmission entry or exit capacity to manage locational constraints. Congestion management tools will be considered further in the Final Report.

contracts to reduce flows. It is important that the entity chooses the instrument that is most efficient in managing the constraints or balancing costs.

In considering the appropriate allocation of new functions between the pipeline owner and system operator, the AEMC has had regard to the current separation of APA as the pipeline owner and AEMO as the system operator, as well as AEMO's status as a not-for-profit entity.[29] The AEMC's proposed allocation of new roles under the Southern Hub is illustrated in Figure 3.1 and explained below.

Figure 3.1 Proposed split of functions between AEMO and APA



3.1.1 Calculating and selling baseline capacity

Under the proposed Southern Hub, APA would be responsible for calculating the baseline level of capacity which must be made available to market participants at entry and exit points on the DTS.

However, unlike the current arrangements where the capacity of the DTS is agreed between AEMO and APA under the terms of the SEA, the level of capacity which APA would be obligated to make available to the market would be determined as part of a regulatory-led process. This would involve APA proposing, and the AER approving, the level of baseline capacity to make available at each entry and exit point (or zone) on the DTS.[30]

The AER is the appropriate body to determine the efficient level of baseline capacity on the basis that the costs of inefficient utilisation of the system are ultimately borne by consumers. This arrangement attempts to link the decision maker (the AER) with the party that bears the costs (consumers, on which the AER is acting on behalf of). In addition, setting the level of baseline capacity through a regulatory-led process will ensure that the process is transparent and that stakeholders have the opportunity to participate.

29 AEMO was established by the Ministerial Council for Energy (MCE), now the COAG Energy Council, as an operational entity by 1 July 2009. AEMO operates on a cost recovery basis and fully recovers its operating costs through fees paid by market participants and network service providers. To reflect it’s not for profit status, AEMO is a company limited by guarantee under the Corporations Act (2001).

30 AEMO would also have a role in this process on the basis that they will be operating the system to the approved level of baseline capacity.

Under the terms of its access arrangements, APA would then be obligated to offer for sale the baseline level of capacity at each entry and exit point on a fair and non-discriminatory basis. This would occur through, for example, auctions of standardised products. Mechanisms for allocating baseline capacity are discussed in Chapter 4.

The entry and exit capacity products would have a reserve price, also determined through the regulatory process, potentially guided by a set of principles set out in the rules. APA would recover its allowed revenue through the sale of baseline capacity products. The approach to setting tariffs for baseline capacity is discussed in Chapter 5.

An overview of baseline capacity is provided in Box 3.2 below.

Box 3.2 Calculating baseline capacity

The approach and methodology used to calculate baseline capacity is important because it determines the amount of firm capacity which must be made available by the pipeline owner at each entry and exit point to and from the system. In an efficient market, all capacity which is operationally available on the day would be allocated and used, and demand for additional capacity would signal the need for new investment.

In a meshed network like the DTS, daily capacity at entry and exit points is not constant over time. Rather, it is influenced by flow patterns and operational constraints on the day.[31] This makes setting the level of baseline capacity challenging particularly in a system that exhibits high seasonality of flows:

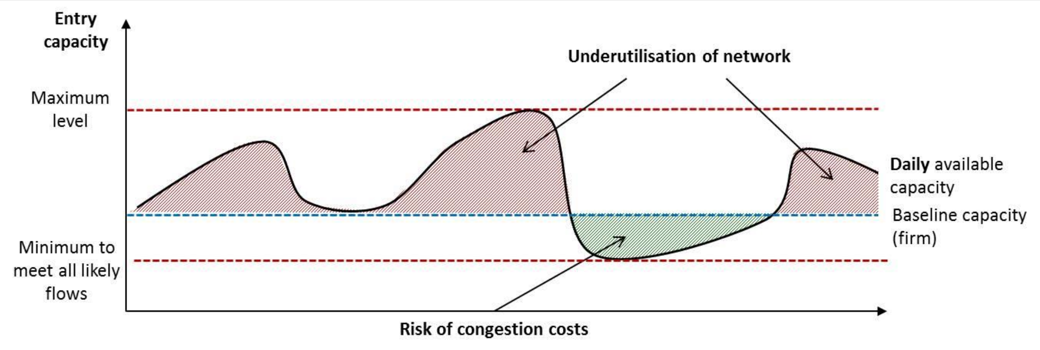
- If the level of baseline capacity is set conservatively, there may be days where additional capacity above the baseline is available at an entry or exit point, but which has not been made available to market participants. In the absence of mechanisms which provide for the sale of additional, generally shorter term, capacity above the baseline, this approach risks inefficient utilisation of the system.[32]
- If the level of baseline is set more aggressively, there may be days where the total level of baseline capacity across all entry and exit points cannot be delivered simultaneously, requiring the system operator to have to take action to manage the resulting constraints. While reducing the risk of inefficient utilisation of the system, this approach increases the risk of congestion costs being incurred and smeared across network users.

31 Localised congestion can arise on a gas network when physical flows change in a way that the system cannot accommodate. In addition to residual balancing role, AEMO would be the party responsible for managing this localised congestion. This issue is touched upon in Chapter 6.

32 The concept of 'additional' capacity is discussed in Box 3.3 below

Setting the baseline level of capacity therefore requires a trade-off to be made between maximising the utilisation of the system and minimising the risk of congestion costs arising. Baseline capacity also only provides a snapshot of the capability of the network. This trade-off is illustrated in the figure below.

Figure 3.2



In most European entry-exit systems, this trade-off is made as part of a regulator-led process. Pipeline owners are, in almost all instances, funded through a regulated revenue allowance. Although they receive revenue from the sale of baseline capacity, the amount of revenue that can be recovered is fixed and hence there is no financial incentive for pipeline owners to want to maximise the release of baseline capacity to the market. On the other hand, pipeline owners are exposed to a financial penalty in the event of non-delivery of the baseline level of capacity. The incentive is therefore to ensure that baseline capacity is set as conservatively as possible.

In the absence of financial incentives on pipeline owners to maximise the release of baseline capacity, regulators are best placed to make the trade-off between maximising the utilisation of the system and minimising the risk of congestion costs. The aim is to set baseline capacity at the level where the benefits of releasing an additional unit of firm capacity to the market are greater than the costs to network users from the system operator having to take action to manage the resulting constraints.

In considering this trade-off, regulators would need to have regard to a number of factors, including:

- The level of capacity that the pipeline owner can reasonably be expected to provide, given that it will be exposed to a financial incentive for the non-delivery of pipeline capacity.
- Any statutory obligations (for example planning criteria[33]), customer requirements and physical limitations on the network.

33 There is currently no statutory planning standard for the DTS in Victoria. When determining pipeline capacity in the DTS, AEMO has required the use of a 1 in 20 planning and system security standard. However, this has been "inherited" from the pre-privatisation, pre-spot market, Victorian

- Whether and what the efficient level of congestion on the system may be.
- Whether additional tools and mechanisms are available to release additional capacity above the baseline, in order to minimise any inefficiencies associated with under-utilisation of the system.
- The seasonal nature of flows on the DTS and whether seasonal baseline entry and exit capacities should be set.

3.1.2 Calculating and selling additional capacity above the baseline

To help maximise the efficient utilisation of the DTS, the Southern Hub model would include a mechanism to allow for the release of additional, shorter term capacity above the baseline level. The release of additional capacity above the baseline would be the responsibility of AEMO and would occur before the gas day and on an interruptible basis. Importantly, this capacity would only be available at entry and exit points where baseline capacity has been fully sold.

As the system operator, AEMO has the best knowledge of the expected pattern of flows and operational constraints on the network each gas day. As such, it will be in the best position to determine whether, and how much, additional capacity above the baseline will be available at each entry and exit point on the DTS. The options for mechanism to offer any additional capacity to the market are discussed further in Chapter 4.

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

The revenues AEMO received from the sale of interruptible capacity would be used to offset any otherwise unallocated congestion management costs. Revenues could also be used to offset participant fees. An overview additional capacity is provided in Box 3.3 below.

Box 3.3 Calculating additional capacity

The inefficiencies associated with the under-utilisation of capacity can be mitigated to some extent by including a mechanism which allows for the selling of additional, generally shorter term, capacity above the baseline.

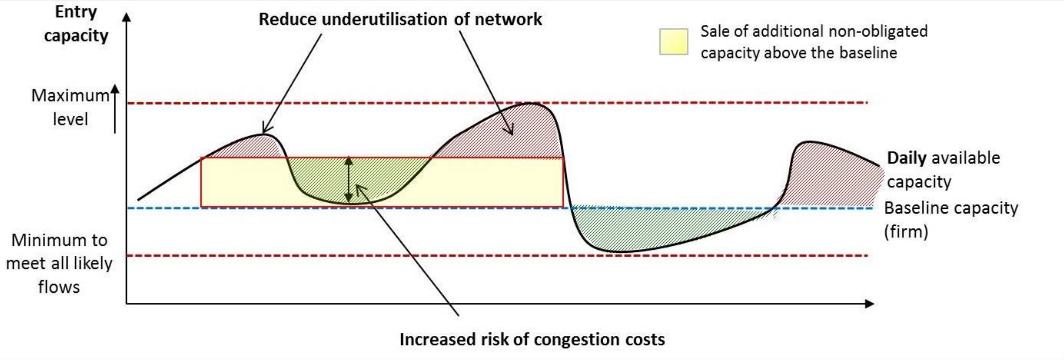
Consistent with the approach to setting baseline capacity, decisions as to what

Gas and Fuel Corporation standard and is consistent with system security standards in use in some international gas systems, including Britain. To increase certainty and provide greater clarity and understanding around the approach to determining pipeline capacity in the DTS going forward, there may be merit in reviewing the planning standard and the governance around this.

level of above-baseline capacity should be made available to the market also require a trade-off between maximising utilisation of the network and minimising the risk of incurring congestion costs.

Ideally, an efficient trade-off would be made where the party responsible for making the decision on how much additional capacity to make available above the baseline, is also the party exposed to the costs of having to manage any resulting congestion. This trade-off is illustrated in the figure below.

Figure 3.3



In Britain, National Grid Gas (NGG) in its role as the system operator may decide to make the additional capacity available over and above the obligated level that NGG, as transmission owner, must make available. It may do so without new investment, by managing flows on the system. The revenue from this ‘non-obligated’ capacity is retained by the system operator.

NGG as the system operator also earns the revenues from any interruptible capacity sold at daily or within-day auctions. By earning revenue on these capacity sales, NGG is incentivised to maximise the capacity being offered to market participants and has a revenue stream to use to offset any costs associated with managing constraints on the network, which may arise from the capacity sold not being able to be used by all market participants concurrently.

Achieving an efficient allocation of above-baseline capacity is more complex where the party responsibly for selling above-baseline capacity, and the party responsible for system operation and managing congestion, are separate entities.

It is for this reason that AEMO as the system operator is likely to be best placed to allocate any additional capacity above the baseline level, where this available. However, the ability to use financial incentives to encourage efficient decisions will be limited by AEMO’s status as a not-for-profit entity.[34]

34 In EU gas markets, the entities that build and allocate capacity, manage congestion and undertake balancing, tend to be integrated, for-profit private or state-owned organisations. Many operate under an incentive regime aimed at co-optimising capacity release and system operation. In Victoria, the ability to achieve a similar outcome is restricted by AEMO's not-for-profit status, which prevents the use of financial incentives, and the separation of APA as the pipeline owner and AEMO as the system operator.

3.1.3 Residual balancing

Finally, under the proposed Southern Hub, AEMO would also perform the residual balancing role in the Southern Hub. In the event that network users do not balance their injections and withdrawals sufficiently, AEMO will be responsible for taking balancing actions to maintain the network pressure within safe operational limits. In its role as residual balancer, AEMO would use line-pack or trade gas at the Southern Hub in order to maintain overall system balance. The Southern Hub gas balancing regime is discussed in Chapter 6.

Box 3.4 Stakeholder questions

The Commission welcomes stakeholder views on any of the issues raised in this chapter. In particular, we are interested in the following:

- Given existing allocation of roles between pipeline owner and system operator in the DTS and DWGM, whether the proposed allocation of system operation functions at the Southern Hub is appropriate and likely to achieve the optimal balance between efficient use and efficient operation of the system.

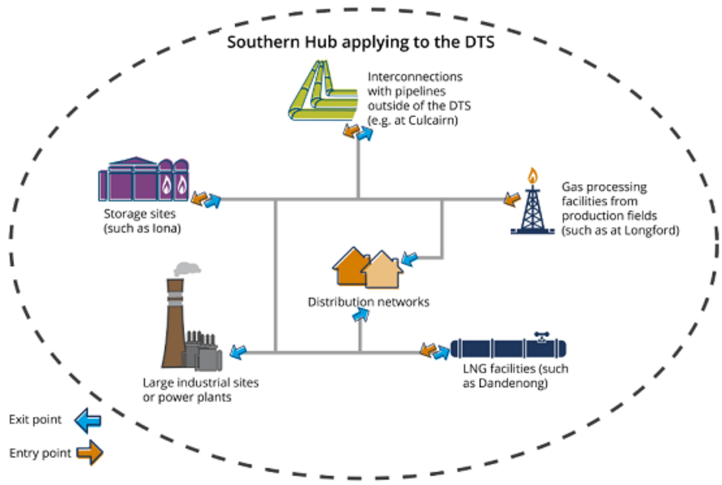
4 Mechanisms for allocating capacity at the Southern Hub

Under an entry-exit system, parties would need to buy one unit of entry capacity in order to flow one unit of gas onto the system and one unit of exit capacity in order to flow one unit of gas off the system. This means that anyone wishing to buy or sell gas at the Southern Hub and have it withdrawn from or injected to the DTS would need to hold sufficient entry and/or exit capacity to do so.[35]

If a party flows more gas than it holds at an entry or exit capacity for any given gas day, then it will incur an overrun charge. The overrun charge places a financial incentive on shippers to buy all the DTS transmission capacity they need. Generally, overrun charges would be set to reflect the price paid for capacity and the costs of managing congestion at the entry or exit point.

'Entry' points are those where gas is injected onto the transmission network, while 'exit' points are where gas is withdrawn from the transmission network. The DTS has a number of such points, some of which serve both entry and exit purposes, while others serve only entry or exit purposes. These are summarised in stylised figure below.

Figure 4.1 Existing entry and exit points on the DTS



While it is expected that baseline[36] entry and exit capacity will be defined so that the DTS will operate almost always without congestion, there will still be times when demand for existing baseline capacity exceed supply and so will require allocation. Under certain circumstances it will also be efficient for such scarcity to trigger investment in new capacity to meet future demand - that is, investment in what is referred to as 'incremental capacity'.

35 Parties wishing to solely trade gas products at the Southern Hub prior to their delivery date (for example, financial traders) would not require entry and/or exit capacity so long as they close out their physical positions prior to delivery.

36 'Baseline capacity' refers to the amount of capacity which APA is obligated to provide to the market at each entry and exit point, and against which the system operator must manage the network, usually under normal operating conditions. Baseline capacity is discussed in chapter 3.

This section outlines the commonly adopted mechanisms for allocating existing baseline capacity in European entry-exit models and for triggering incremental capacity investments. It also discusses the technical nature of entry and exit points to the DTS before presenting the Commission's preliminary view on the most appropriate mechanism for allocating transmission capacity at entry and exit points within the Southern Hub. A discussion on transitioning AMDQ and AMDQ cc concludes this chapter.

4.1 Principles of allocating entry and exit capacity

Participants wishing to inject or withdraw gas to/from the DTS will require capacity rights to do so. Such injections and withdrawals may be a result of buying or selling gas on the wholesale market, or a result of individual upstream gas supply contracts.

The entry-exit system would provide market participants with non-discriminatory access to entry and exit capacity, allowing them to compete effectively for gas at the Southern Hub. This means that all participants would be offered entry and exit capacity on the same basis.[37] Non-discriminatory access to transmission capacity will enable market participants to respond to market price signals in the Southern Hub and so facilitate gas going to the parties that value it the most.

Entry and exit points can be classified into two broad groups, depending on the ability of parties to control gas flows. Specifically, points where parties have:

1. the ability to control the quantity of gas injected to, or withdrawn from, the DTS with respect to price (and hence the entry/exit capacity required); and

2. no ability to control the quantity of gas withdrawn from the DTS with respect to price (and hence the entry/exit capacity required).

The first category covers all entry points, as well as exit points such as interstate exports and gas withdrawn into the Iona underground gas storage facility. The second category applies to almost all customers in the residential, commercial and industrial sectors, as well as gas fired power generators, since their demand is dictated by prices in the National Electricity Market.[38]

For both categories, if demand for capacity falls short of available baseline capacity, then all requests for baseline capacity can be met and capacity allocated accordingly.

However, entry and exit baseline capacity can at times be scarce and must be allocated among market participants in a manner that promotes competition and security of supply. A mechanism is therefore required to allocate baseline capacity during times of scarcity in a transparent, efficient and non-discriminatory manner. There are a range of mechanisms available to allocate baseline capacity, as outlined in the sections below,

37 For example, market participants would be offered the same capacity products on the same terms as each other.

38 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, May 2012, p. 15.

although each varies in its appropriateness for allocating capacity at the two different categories of entry and exit points outlined above.

While demand for existing baseline capacity will naturally exceed supply from time-to-time, and need to be allocated between parties accordingly as outlined above, there are certain circumstances where it is efficient for such scarcity to trigger investment in new capacity to meet future demand. This is referred to as investment in incremental capacity.

At a high level, these circumstances are when the collective willingness to pay for incremental baseline capacity is greater than the long-run marginal cost of providing it. This is a distinguishing feature between when it is efficient to make incremental baseline capacity available and when it is efficient to ration demand or make available additional existing capacity.

A mechanism therefore needs to be developed that identifies when these circumstances arise and thus allow investments in incremental baseline capacity to be made. Such a mechanism ensures that efficient investment in incremental capacity is made in a timely manner and that the risks borne by those parties best placed to manage them.

The two prerequisites of such a mechanism are that:

- parties can signal their willingness to pay for incremental baseline capacity; and
- the collective willingness to pay for this incremental baseline capacity can be assessed against the cost of providing it.

The box below outlines the concept of a 'market test', which essentially assesses the collective willingness to pay for this incremental baseline capacity against the cost of providing it.

Box 4.1 The concept of a 'market test'

The risk of inefficient investment should lie with the parties that are best placed to forecast and manage that risk. In order to avoid consumers bearing undue risk of inefficient investment, shippers in entry-exit systems are typically required to make binding commitments to purchase capacity as part of what is known as a 'market test'. A market test provides evidence that the investment is required and reduces the risks for consumers (or APA) who would otherwise bear the risk.

Essentially, a market test assesses whether the value of expected future payments from shipper commitments covers an adequate proportion of projected infrastructure cost for the incremental capacity. This corresponds to traditional investment appraisal procedures and takes into account the willingness to pay of individual network users.

We understand that the experience in Europe has been that network users are not willing to make financial commitment to buy incremental capacity for the entire length of the assumed asset lives of gas transmission assets. For example, shippers may only be willing to make commitments to buy incremental capacity for between 5 and 15 years from the commissioning date, which can be shorter than the typical depreciation period used for regulated gas transmission assets. As a consequence, consumers may bear the residual risk that the asset is inefficiently utilised in the future.

The fundamental requirements for the passing of a market test is therefore that expected network user payments is expected to exceed the portion of investment costs that should be recovered via network user commitments. The latter should be calculated as the investment cost multiplied by a predefined fraction of these costs that is deemed to be recoverable from network users, taking into account, amongst other things, the time horizon network users are likely to enter into such commitments.

4.2 Mechanisms for allocating baseline capacity

A process is required to ensure that baseline entry and exit capacities are allocated between parties in an efficient manner during times of scarcity. It is important also that this mechanism allows for a robust market test to be conducted to determine whether investment in incremental capacity is efficient.

There exist a range of mechanisms that have been applied elsewhere, including:

- auctioning capacity;
- pro-rating capacity;
- first-come-first-served; and
- capacity tied to end-use customers.

An overview of each of these mechanisms is provided in the sections below, including both where they have been applied elsewhere and their appropriateness for the two broad categories of entry and exit points outlined above.

4.2.1 Auctioning capacity

An auction mechanism uses price to allocate baseline capacity at entry and/or exit points between parties during times of scarcity. Specifically, if demand for capacity at an entry and/or exit point exceeds the available baseline capacity, available capacity will be allocated between parties based on their willingness to pay for it.

A well-designed auction mechanism promotes competition between bidders and those who place a relatively high value on the capacity being auctioned will generally be willing to bid highest for it. Auctions can therefore assign capacity to those who value it the most and deliver an efficient allocation of baseline capacity.

The ability of an auction to allocate capacity efficiently relies on parties having the ability to control the quantity of gas withdrawn from the DTS with respect to price (and hence the entry/exit capacity required). An auction may therefore be an appropriate mechanism for allocating capacity at entry points in the Southern Hub, as well as interstate export exit points and gas withdrawn into the Iona underground gas storage facility. However, auctions are unlikely to be appropriate for allocating capacity at exit points serving residential, commercial and industrial sectors, as well as potentially exit points serving gas fired power generators.

While auctions have the potential to allocate baseline capacity efficiently among parties, they can also perform this task poorly if they are not carefully designed and undertaken. Specific market conditions and design issues can distort auction outcomes and affect the efficient allocation potential of an auction.

In particular, where there are only a small number of parties active at an entry or exit point, there is a risk that some parties may be able to exploit their dominant position and to block small shippers from access to baseline capacity. In these circumstances, anti-hoarding mechanisms are likely to be required.

Auctions are commonly used to allocate transmission capacity in European gas markets.[39] Indeed, auctions using a common platform are used to allocate capacity at all cross-border interconnection points in European gas markets. This is required by European legislation to ensure non-discriminatory access to capacity and that tariffs reflect the scarcity value of pipeline capacity. Other than in Britain where auctions are also held for all entry points on the network, first-come-first-served (FCFS) tends to be the main mechanism used for capacity allocation at non-interconnection points. FCFS is discussed in section 4.2.3.

For other member states, auctions are used to allocate capacity at cross-border interconnection points, as required by the European network code on capacity allocation.[40] For non-interconnection points, first-come-first-served (FCFS) tends to be the main mechanism used for capacity allocation. FCFS is discussed in section 4.2.3.

Auctions can be designed to allocate not only existing baseline capacity but also trigger investment in incremental capacity. Auctions serving this dual purpose are referred to as 'integrated auctions' and are discussed in section 4.3 below.

4.2.2 Pro-rating capacity

A pro-rata mechanism uses a predefined method to apportion requested capacity at an entry and/or exit point when demand exceeds the available baseline capacity. Such a method may involve reducing all requests in proportion to requested capacity.

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39 KEMA, *Entry-Exit Regimes in Gas - Country Factsheets*, 19 July 2013.

40 It is legislated that capacity at interconnection points in Europe is auctioned using a common platform to ensure non-discriminatory access to capacity and that tariffs reflect the scarcity value of pipeline capacity.

A pro-rata mechanism is a relatively simple mechanism to allocate capacity during times of scarcity and, unlike an auction, does not require active participation by parties. However, since it does not use price to allocate available baseline capacity between parties, it is unlikely to result capacity being allocated to those that value it the highest.

A pro-rata mechanism may also require a separate process to be developed to assess the collective willingness to pay for this incremental baseline capacity against the cost of providing it. Specifically, a pro rata mechanism will provide insight as to how much incremental capacity parties would like at the existing reference tariffs but not how much they are willing to pay for incremental capacity collectively.

The application of a pro-rata mechanism to points may provide parties an incentive to over-book capacity at entry and/or exit points to ensure they can always access the capacity they require, that is, even during periods when requested capacity is pro-rated. There is also the risk with such a mechanism that requested capacity may be reduced so much that the capacity allowed is not commercially beneficial to the requesting party.

A pro-rata mechanism essentially guarantees all parties that request capacity that they will have access to some minimum amount. Pro-rata mechanisms may therefore be a useful tool when there is a risk that some participants may be able to exploit their dominant position in auctions and to block small shippers from access to capacity, for example, in immature or undeveloped markets when effective levels of competition have not yet developed.[41]

We understand that pro-rata mechanisms are not widely used in Europe. GRTgas, the system operator in the north and south of France, is one of the few that applies a pro-rata mechanism if long-term capacity made available falls short of demand.[42]

4.2.3 First-come-first-served

Applying a first-come-first-served mechanism involves allocating available entry and exit capacity according to the order that parties request it.

Similar to a pro-rata mechanism, FCFS represents a relatively simple mechanism to allocate capacity during times of scarcity and, unlike an auction, does not require active participation by parties. However, a FCFS mechanism will not allocate baseline capacity efficiently between parties when demand for capacity at an entry and/or exit point exceeds the available baseline capacity. Specifically, since parties can secure capacity using means other than price (that is, simply requesting baseline capacity before it is exhausted), a FCFS mechanism will not allocate baseline capacity to parties that value it the most.

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41 European Regulators Group for Electricity and Gas, *ERGEG principles Capacity allocation and congestion management in European gas transmission networks*, December 2009, p. 18.

42 KEMA, *Entry-Exit Regimes in Gas - Country Factsheets*, 19 July 2013, p. 87.

A FCFS mechanism, like the pro-rata mechanism, will also require a separate process to be developed to assess the collective willingness to pay for this incremental baseline capacity against the cost of providing it. Specifically, a FCFS mechanism alone provides no insight as to how much they are willing to pay for incremental capacity collectively.

The FCFS method of allocating baseline capacity encourages parties to make decisions regarding capacity procurement well in advance of when they ultimately require the capacity. If this capacity cannot be reallocated using a secondary market, then this can be considered to lower short-term wholesale trading flexibility as partes wishing to buy or sell gas at a particular entry and/or exit point may be precluded from accessing the capacity to do so.

A risk associated with the FCFS mechanism is that parties, especially incumbent parties, may hoard capacity through over-booking it. Such hoarding, if unaddressed, would create a barrier to entry for new parties since capacity they wish to access would not be available.

The application of a FCFS mechanism may result in a 'crowding out' of capacity *within* the DTS by capacity *across* the DTS. Specifically, if parties wishing to transit gas across the DTS for export are prepared to book exit capacity for longer durations than parties serving internal loads, FCFS could restrict the availability of exit capacity for shippers serving internal consumers since APA would be limited in the baseline capacity it can offer.

We understand that most European gas hubs allocate baseline capacity using a FCFS mechanism. However, they also typically have significant excess capacity and so periods of scarcity are rare. A number of European gas hubs complement their FCFS allocation mechanism with an auction or a pro-rata mechanism to apply in the case of congestion.[43]

4.2.4 Capacity tied to end-use customers

In instances where parties do not have any direct control over their gas use, and hence capacity demanded from the DTS, it may be appropriate to adopt a mechanism that allocates capacity to those responsible for the party's gas use in an automated manner. This is often the case for retailers who cannot control how much gas their end-use customers use, although being ultimately responsible for the associated wholesale gas and capacity procurement.

In these circumstances it is common to automatically allocate baseline capacity at exit points at the distribution network to retailers based on their downstream market share. There are no explicit capacity bookings at the exit point. Instead, these are calculated automatically. This is essentially akin to how AMDQ for Tariff V customers (that is, all

43 KEMA, *Entry-Exit Regimes in Gas - Country Factsheets*, 19 July 2013.

residential and small-to-medium sized commercial and industrial customers) is allocated currently.[44]

An automatic allocation mechanism avoids retailers having to proactively procure exit capacity ahead of when they anticipate requiring it. Requiring retailers to actively procure capacity may result in an inefficient allocation of capacity as a result of customer churn. Such a requirement may also create a barrier to entry for new retailers if all exit capacity is booked by incumbent retailers.

We understand that an automatic allocation mechanism is applied for exit points to the distribution network in a number of European gas hubs. For example, in both the northern and southern French gas hubs, each shipper present at a distribution exit point automatically receives an allocation of transmission capacity corresponding to the capacity allocated on the distribution network.[45]

An automatic allocation mechanism does not use price to allocate baseline capacity between parties. However, this is appropriate given retailers cannot alter their demand for capacity with respect to its price. More broadly, we would still expect capacity to go to those that value it the highest via the process of retail competition.

4.3 Mechanisms for triggering new baseline capacity

A process is required to determine when it is efficient to make incremental baseline capacity available, versus when it is efficient to ration demand or make available additional existing capacity. Such a mechanism should trigger and allocate additions to, and expansions of, capacity that enable supply to meet demand while minimising the cost of excess capacity.

The two market-based mechanisms available to do this are:

- open seasons; and
- integrated auctions.

Each of these is outlined in the sections below.

An alternative to a market-based mechanism is to develop a centrally coordinated planning mechanism. However, it is the Commission's view that a well-designed market-based mechanism will deliver more efficient outcomes than an administrative-type mechanism, where possible.

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44 The rationale for allocating the original AMDQ to customers rather than market participants, retailers or shippers was to not create a barrier to retail competition. For example, if AMDQ were held by retailers, there was a concern that those retailers who won customers from rival retail businesses would then be forced into a position of either trying to negotiate with that rival retailer to sell them AMDQ, or take on additional risk.

45 KEMA, *Entry-Exit Regimes in Gas - Country Factsheets*, 19 July 2013, p. 85.

4.3.1 Open seasons

The term 'open seasons' refers to distinct, predefined periods of time for when parties can request capacity for future periods. Open seasons serve to confirm the collective desire of shippers to make binding commitments to purchase capacity.

Open seasons can include either:

- incremental capacity; or
- existing unsold capacity together with incremental capacity.

Under the first method, the open season would be run as a separate process for determining whether to invest in incremental capacity. If the market test was passed, then incremental capacity would be allocated based on the binding requests for capacity received.

The second method would be the same process as the first except that the open season would offer incremental capacity together with any existing unsold capacity. The intention of integrating these two is to reflect the fact that shippers are interested in the capacity product and not whether it already exists or is considered to be incremental. This method may also be administratively simpler - that is, only having one mechanism for allocating existing unsold capacity as well as future, incremental capacity.

Open seasons may include both a 'non-binding' and a 'binding' phase. The non-binding phase precedes the binding phase and serves to provide a preliminary gauge as to the collective demand for future capacity use by parties.

In Europe, efforts to achieve market-driven investment have mainly taken the form of open seasons. However, this approach was developed at a time when existing long-term capacity was mainly allocated using open subscription periods with pro-rata or FCFS. This implied that capacity was automatically allocated at the regulated tariff.[46]

A number of issues with open seasons have been raised in Europe, including:[47]

- no clear trigger or conditions to start an open season process, leaving potentially unsatisfied demand from existing and potential shippers;
- where open seasons have a non-binding phase, it is perceived to be unreliable because shippers have no incentive to make their statements about capacity needs realistic;

46 Council of European Energy Regulators, *CEER Blueprint on Incremental Capacity*, 23 May 2013, p. 10.

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

- shippers see a lack of transparency concerning the value of investment in relation to capacity on offer and the allocation of risk between the parties;
- pressure from shippers for greater visibility concerning the derivation of tariffs and greater certainty about how they will evolve;
- transparency issues in relation to the market tests applied;
- requests from regulators to withhold a percentage of the incremental capacity for short-term allocation, reducing the potential longer-term shipper commitment and risks to the system operator;
- unclear rules on allocation of capacity in some cases (some open season procedures give priority to longer-term demand, some to the highest price offered); and
- the respective roles of regulators and system operators not always being clear.

The Commission would be interested to hear the views of parties on the extent of these problems should an open season mechanism be developed for the Southern Hub.

4.3.2 Integrated auctions

Integrated auctions can be applied to not only allocate existing capacity but to also signal the need for incremental capacity investments. Specifically, these auctions offer both existing capacity and incremental capacity and serve two purposes:

- allocate existing capacity at a price premium when capacity is scarce and the market test for incremental capacity is not met; and
- provide demand and price data that can be used as an input to the market test concerning whether to release incremental capacity and, if the test is met, to allocate such incremental capacity.

Integrated auctions necessitate a schedule of increasing price increments against which parties can indicate their willingness to pay for capacity in the form of the quantity bid for each price. Each of the price increments also needs to also be paired with a potential incremental quantity of capacity and the investment cost required to deliver this capacity. Importantly, the auction should create the right signals but also avoid creating opportunities for gaming by participants.

An overview of how an integrated auction might work in practice is provided in the box below.

Box 4.2 How integrated auctions trigger new capacity

Suppose APA[48] is running an auction for capacity at a particular entry point (eg, Longford) for future quarters and the auction is an integrated auction, ie, it is designed to both allocate existing capacity, as well as signal interest in expansions of capacity.

Interested market participants would register with APA in order to participate in the auction. This registration process would include assessment of any prudential or credit requirements.

At a high level, the auction process would occur as follows:

- Step 1: APA would circulate a price schedule to registered participants;
- Step 2: Market participants would then bid in the quantity of capacity they want at each quarter, at each price step; and
- Step 3: APA would then assess the level of demand, and the amount of capacity that can be offered. This would involve considering whether investment in incremental capacity may be beneficial.

If demand for capacity is less than, or equal to the existing capacity, then APA will simply allocate firm capacity to parties. For example, if the existing entry capacity of the entry point is 990TJ and for the first two quarters of Year 1 the level of capacity demanded is 500TJ and 780TJ, respectively, then participants will simply be allocated these firm capacity rights.

However, if there is more demand for capacity than is currently provided, that is, bids sum to greater than 990TJ, then incremental capacity investment and release of more baseline capacity may be beneficial. APA would look to see if there was any quarter where the bids for a given quantity of capacity exceed the offered supply of capacity. For example, parties may collectively bid for 1,450TJ and 1,500TJ of entry capacity for the second and third quarters in Year 2 (that is, winter).

In order for APA to consider whether the increased capacity would be beneficial or not, it would compare the results of the auction (that is, bids received) to an estimate of the costs necessary to upgrade the network. Final investment approval for projects aimed at releasing incremental capacity will also involve the AER's approval.

National Grid is the only system operator in Europe to offer incremental capacity at all entry points on its network, excluding cross-border capacity, every year using integrated auctions.

48 This example assumes that APA would be the party responsible for running capacity auctions.

4.4 International approaches to capacity allocation

This section outlines how existing capacity is allocated and new capacity triggered in Britain and the Netherlands, widely considered to be the two most developed European gas hubs.

4.4.1 Britain[49]

National Grid is the transmission owner and system operator of the national transmission system (NTS). As part of its role, National Grid is obliged to ensure that adequate NTS capacity is available to support gas flow requirements. This is done in part by managing the allocation of entry and exit capacity.

National Grid makes available entry capacity and exit capacity via its Gemini system, which shippers are obliged to book in order to have the right to flow gas to and from the system on behalf of customers. National Grid aggregates injection and withdrawal points on the NTS into several entry zones and many exit zones.

Entry capacity

National Grid operates a number of entry capacity auctions for users to secure access to the NTS. Entry capacity is made available in quarterly, monthly or daily firm and interruptible strips via a suite of long and short term reserve price auctions. These auctions also allow users to trigger the release of incremental entry capacity to secure additional capacity at NTS entry points.

For each system entry point, capacity is made available on a firm and interruptible basis. All entry capacity is offered on a pence per kWh per day basis, where the quantity is measured in terms of an end of day entitlement. Interruptible Capacity is limited to being offered on a daily basis in an auction that is conducted the day ahead of the intended day of use.

Exit capacity

NTS exit capacity provides shippers with a right to off-take gas from the NTS. As with entry capacity, National Grid is obligated to provide a baseline amount of firm exit capacity as well as incremental capacity in response to market demand. It may also provide a non-obligated volume at its discretion. Shippers obtain exit capacity by through a number of application windows and auctions.

There are a range of exit capacity products available, including capacity for set periods (annual and daily), ongoing capacity ('enduring' capacity), off-peak capacity etc. Enduring capacity and annual capacity products are allocated by means of application windows, whilst the daily and off-peak products are released through auctions.

49 This section is based on information available at: http://www2.nationalgrid.com/Britain/

Reserve prices for daily capacity auctions are equal to the enduring capacity charges. The reserve price for off-peak capacity, which is auctioned on a daily day-ahead basis, is zero.

4.4.2 The Netherlands[50]

Gasunie Transport Services B.V. (GTS or Gasunie) is owner and operator of the national transmission network in the Netherlands. Gasunie applies an entry-exit system where gas flows into the network at entry points and leaves the network at exit points. Shippers can book transport capacity at entry points and exit points and tariffs are set for all entry and exit points by the Dutch Authority for Consumers & Markets.

Bookings can be for capacity at *internal* connection points or cross-border *interconnection* points.

Booking capacity at internal points

Entry and exit capacity at all points other than the cross-border interconnection points and distribution exit points are offered on a FCFS basis via the European capacity platform PRISMA. Parties directly connected to the transmission system can book exit capacity themselves. Once exit capacity is obtained, these parties have to transfer it, possibly through their gas supplier, to the shipper with whom they have a gas supply contract.

Distribution exit capacity is made available by Gasunie for exit points connected with the distribution network. The capacity at these points does not need to be pre booked by shippers, instead the capacity is charged monthly in retrospect based on details regarding market share.

Booking capacity at cross-border interconnection points

Entry and exit capacity at cross-border interconnection points is auctioned via the same PRISMA platform. Gasunie offers yearly, quarterly, monthly and daily capacity products at these points. Ten percent of the technical capacity at the interconnection points must be reserved for quarterly, monthly and daily auctions. If less than 10 percent is available, then no capacity is offered as a yearly product and all available capacity is offered via quarterly, monthly and daily auctions.

The capacity to be auctioned consists of not only the available technical capacity but can also include capacity that shippers want to offer in the context of Surrender of Capacity via Gasunie on PRISMA. As part of the Congestion Management Procedures,

50 This section is based on information available at: https://www.gasunietransportservices.nl/en/shippers/capacity-booking/entry-exitcapacity

Gasunie offers Oversubscription & Buy Back (OBB) capacity at interconnection points experiencing contractual congestion.[51]

In principle, the capacity available at the interconnection points is auctioned as bundled capacity as far as possible. Based on the capacity offered by the system operators, the amount of capacity that can be bundled is specified on the PRISMA platform. Capacity that cannot be matched with capacity on the other side of the border is offered as unbundled capacity.

Gasunie offers interruptible capacity if all firm capacity at an interconnection point is sold out. Interruptible capacity (both forward and backhaul) is only offered as a daily product on a day-ahead basis. Interruptible capacity has a probability of between 0 percent and 15 percent of being interrupted and the tariff reduction is 30 percent.

4.5 Characteristics of the Southern Hub entry and exit points

There are a number of points where gas can flow on-to and/or off-from the DTS currently. Specifically:[52]

- 4 points where parties can control their injections of gas to, but cannot control gas withdrawals from, the DTS. These are production injection points and Dandenong storage;
- 123 points where parties can withdrawal gas from, but cannot control gas injections to, the DTS. These are large transmission connected customers and distribution networks; and
- 5 points where parties can both inject and/or withdrawal gas to/from the DTS. These are interconnection points and Iona storage.

These can be further broken down into the two categories of points outlined in section 4.1 above, that is, those that can and those that cannot control their gas flows.

The figure below presents a stylised overview of the three broad categories of existing entry and exit points in the DTS. Specifically:

- Purple denotes production entry points, interconnection entry/exit points and storage entry/exit points.
- Green denotes distribution exit points.
- Orange denotes direct connect exit points.

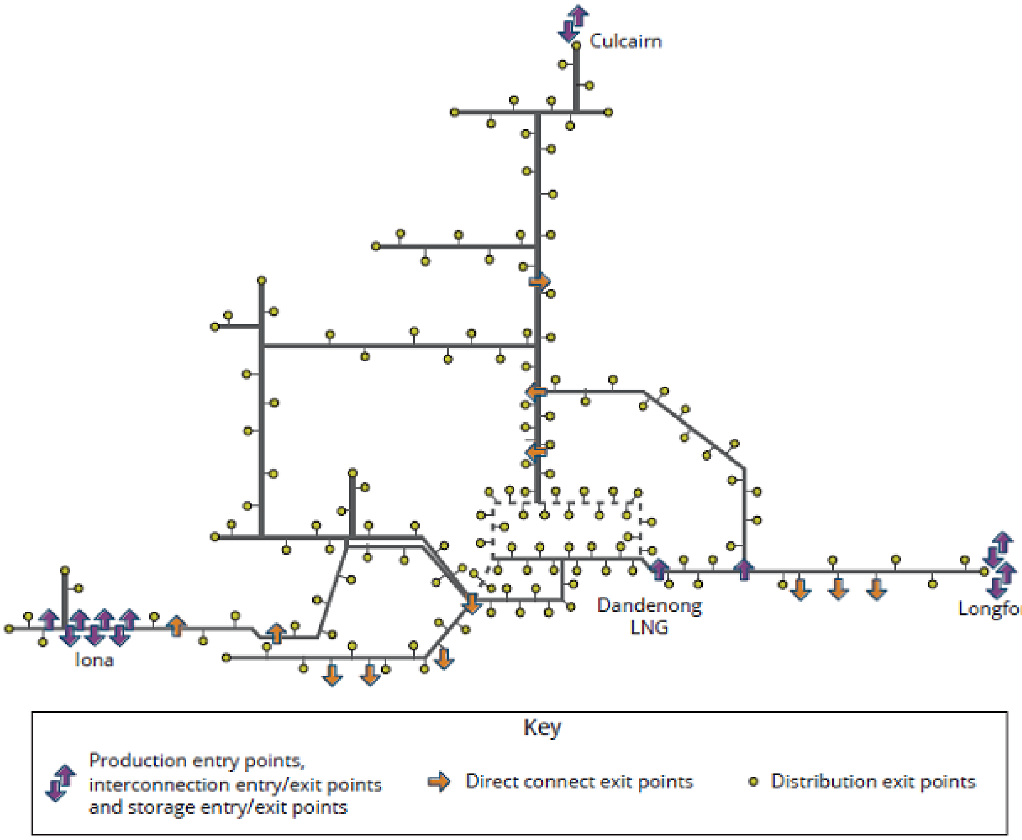
Please note that entry and exit point locations are only intended to be illustrative. For example, not all 111 distribution exit points have been represented in the figure below.

51 The OBB mechanism is also applied in Great Britain by National Grid. However, unlike Gasunie, National Grid is able to offer additional capacity at all entry points, not just interconnection points.

52 Data provided by AEMO.

In addition, we note that many distribution exit points are grouped together and gas withdrawals are only measured at the aggregate grouped-level.

Figure 4.2 Existing entry and exit points to the DTS



4.6 The Commission's preliminary view on capacity allocation

The Commission's preliminary view is that capacity should be allocated using the following mechanisms:

- Auctions for points where parties have the ability to control the quantity of gas injected or withdrawn from the DTS with respect to price (and hence the entry/exit capacity required) - these points include:
  - the 4 production entry points;
  - the 4 interconnection entry and exit points; and
  - the 2 storage entry and exit points.
- Automatic allocation for the 111 distribution exit points, that is, for retailers representing all residential and small-to-medium sized commercial and industrial customers.
- Auctions for the 12 exit points relating to large customers directly connected to the DTS.

While each of these is discussed below, the Commission notes that these views are preliminary in nature and would value the input of stakeholders on each.

4.6.1 Production entry points, interconnection entry/exit points and storage entry/exit points

A well-designed auction mechanism for points where parties have the ability to control the quantity of gas injected or withdrawn from the DTS promotes competition between bidders and can therefore assign capacity to those who value it the greatest. However, we are cognisant of the fact that the success of an auction depends on a number of design and market characteristics and so would be interested to hear from parties on the practicalities of implementing an auction mechanism for these points.

Designing auctions for production entry points, interconnection entry/exit points and storage entry/exit points in an integrated manner (that is, offering both existing baseline capacity as well as potential incremental capacity), allows a market test to be performed to assess when it is efficient to invest in incremental capacity. This should allow for timely and efficient investment additions to, and expansions of, infrastructure that enable supply to meet demand while minimising the cost of excess capacity.

Allowing users to signal the need for incremental investment through entry and exit auctions for these points represents a step-change in reducing the risk of inefficient investment from the current arrangements where investment occurs predominately through the regulatory process. Specifically, requiring users to pre-commit to booking new capacity at entry and exit points means they will bear the costs and risks associated with their usage decisions, rather than those costs being smeared across all consumers.

To implement such auctions, a market test will need to be developed. A fundamental question that needs to be answered as part of doing so is what portion of investment costs should be recovered via network user commitments, and what portion should be recovered by consumers, if any.

4.6.2 Distribution exit points

It is appropriate to automatically allocate baseline capacity at distribution exit points to retailers since they have no direct control over their end-use customers' demand, that is, all residential and small-to-medium sized commercial and industrial customers.

While an automatic allocation mechanism does not use price to allocate baseline capacity between parties, it would not be appropriate to, given retailers cannot alter their demand for capacity with respect to its price. Retaining automatic allocation for retailer customers also minimises the scope of change and the input required by retailers.

Automatic allocation offers no market signals as to when it is efficient to invest in incremental capacity. Instead, this is expected to occur via a bilateral planning process between APA and the distribution business and retailers. We note that this essentially occurs currently whereby APA and distributors need to agree connections.

In addition, we note that existing distribution withdrawal points in the DTS are essentially grouped together and groups face the same transmission charges. The Commission is of the preliminary view that a similar charging arrangement would apply under the proposed Southern Hub model, that is, each of the 111 existing distribution exit points would not face an individually tailored exit tariff. This matter is discussed further in Chapter 5.

4.6.3 Direct connect exit points

Our preliminary view is that an auction platform can also be used to allocate baseline capacity for exit points relating to customers directly connected to the transmission network.

We note that these points will not have the competitive tension of production entry points, interconnection entry/exit points and storage entry/exit points as there is typically only one party per exit point. The auction will therefore be expected to clear at its reserve price.[53] However, administratively, it is likely to be simpler to have directly connected customers using the same auction platform for exit capacity as they will be using to procure entry capacity at production and interconnection entry points.

Where direct connect customers are catered for by a retailer, that is, where they themselves do not procure gas and exit capacity, it might be appropriate to use an automatic allocation mechanism since the retailer cannot directly control the gas use of the end-user.

Due to the lack of competitive tension at direct connect points, a separate mechanism will likely be required to trigger investment in incremental capacity. At this stage, we consider that this should occur through a bilateral planning process between APA and the directly connected customer and, in order to minimise the risk of inefficient investment falling on consumers, we would expect that directly connected customers would have to commit to paying for the capacity for a certain number of years into the future.[54]

4.7 Transitioning AMDQ and AMDQ cc

To move from the existing market carriage arrangements in Victoria to an entry-exit system for allocating capacity, a key issue to resolve would be the transition of existing

53 The setting of which is discussed in Chapter 5.

54 Alternatively, we note that an open season may be able to be run to allow direct connect parties to signal future demands for capacity, although this too would require an additional mechanism to be developed.

(albeit limited) benefits afforded to market participants holding AMDQ and AMDQ cc.[55]

AMDQ and AMDQ cc have value where the customers or market participants holding them intend to flow gas on the parts of the system to which they relate. To provide value, they must be validated with AEMO on the day. Once validated, AMDQ and AMDQ cc provide the holders with:

- higher priority in the scheduling process than a customer with no AMDQ if there is a tie in bids (tie breaking rights);
- higher priority access to the DTS than a customer with no AMDQ if there is a constraint in the DTS that requires the curtailment of some users to maintain system security (curtailment 'protection' rights); and
- a hedge against any associated congestion uplift charges which may arise (uplift hedge).

Congestion uplift hedge

To recover ancillary payments caused by congestion on the DTS, congestion uplift is charged to market participants who have exceeded their allocation of AMDQ and/or AMDQ cc in a scheduling interval (that is, exceeded their Authorised Maximum Interval Quantity (AMIQ)).[56] Market participants who hold AMDQ or AMDQ cc can use part or all of their allocation to hedge against those congestion charges, up to their AMIQ.

In an entry-exit system, if a shipper flows more gas than it holds entry or exit capacity for any given gas day, then it will incur an overrun charge. The overrun charge is the shipper's financial incentive to buy all the DTS transmission capacity that it needs. Generally, overrun charges would be set to reflect the price paid for capacity and the costs of managing congestion at the entry or exit point. In this sense, as long as market participants are able to reserve the amount of entry and/or exit capacity that they expect to use, they will not be exposed to charges caused by congestion on the DTS.

Injection and withdrawal tie breaking rights

The gross pool market design of the DWGM means that, each day, market participants are required to submit bids to withdraw gas from and inject gas into the DTS. AEMO matches supply with demand, and schedules the market based on the lowest price required to meet all demand. When there are equally priced bids, for gas injections or withdrawals, and only some of their combined total bid quantity is required or can

55 For more information on AMDQ and AMDQ cc, see: AEMC 2015, Review of the Victorian Declared Wholesale Gas Market, Draft Report, 4 December 2015, Sydney, Section 5.2; or AEMC 2015, Review of the Victorian Declared Wholesale Gas Market, Discussion Paper, 10 September 2015, Sydney, Appendix C.

56 Each market participant's AMDQ uplift hedge is converted to schedule interval quantities using their nominated AMIQ profile (that is, how much AMDQ that participant expects to use in each schedule interval) to effectively create a hedge generated on an interval basis.

physically be delivered into or from the system, a participant holding AMDQ or AMDQ cc at that location will be scheduled in priority to a participant without AMDQ or AMDQ cc.

The tie breaking rights effectively ensure that parties holding them can match their injections and withdrawals and so will not be exposed to an imbalance payment. In general, market participants endeavour to align their intended daily gas injections and withdrawals to avoid exposure to the spot market, unless the market participants are either sole injectors or withdrawers. However, intended daily gas injections and withdrawals may differ for a given day and market participants must pay the costs for the imbalance quantities in the form of daily imbalance payments.

The proposed entry-exit system will increase the ability of participants to manage the risk of being exposed to the costs of such 'imbalance' gas. As long as participants have booked firm entry-exit capacity at the level needed, and that their nominations for gas flows do not exceed the amount of firm capacity booked, then they will not face this risk.

Curtailment 'protection' rights

The Victorian arrangements for curtailment of gas usage or consumption to manage emergencies and/or preserve system security have been developed by AEMO in consultation with the Victorian Government. Where curtailment is required due to a transmission constraint, the first customers to be curtailed are those Tariff D customers with either no AMDQ or that have used in excess of their assigned AMDQ.[57]

The introduction of the Southern Hub and entry-exit system would not remove the need for arrangements for the curtailment of gas usage or consumption in order to manage emergencies and/or preserve system security in the event of transmission constraints. Precisely how the protection currently afforded to holders of AMDQ and AMDQ cc in these events will be accommodated under the new framework requires careful consideration and consultation. In principle, the arrangements should seek to avoid discriminatory treatment of users who have purchased firm entry and/or exit capacity rights, subject to operational considerations.[58]

This issue will require further consideration and consultation with stakeholders, AEMO and the Victorian Government given the nature of the issue and its relevance to emergency and system security arrangements.

57 These arrangements are published as the Gas Load Curtailment and Gas Rationing and Recovery Guidelines on AEMO's website. The guidelines provide classifications of gas customers, and set out the priority order under which each class of gas customer will be curtailed if curtailment is required to maintain system security. The curtailment of customers who do not hold AMDQ or AMDQ cc reflects requirements under AEMO's Access Arrangement and Rule 343 of the NGR, and is implemented by Table 0 of the Curtailment Tables.

58 For example, AEMO will generally curtail controllable withdrawals (for example, gas powered generation and large industrial customers) before residential or small commercial customers on the basis that there is no ability for AEMO to curtail the latter safely and effectively within required timeframes.

The Commission's preliminary view on transition AMDQ and AMDQ cc

The transition from the DWGM and market carriage arrangements to the proposed Southern Hub gas trading model and entry-exit system will alter (or remove) most of the risks that AMDQ and AMDQ cc allow market participants to manage. In addition, the new market design would provide more options to users to hedge price risks, through either physical or financial trades at the virtual hub, with a wider range of counter-parties.

In order to keep existing holders of AMDQ and AMDQ cc in a position where they can continue to manage these risks, these market participants would be given the option of acquiring an allocation of firm entry/exit capacity up to their current allocation of AMDQ and AMDQ cc, at the relevant entry/exit point. The allocation of firm capacity would be guaranteed for those market participants who request it, and would be allocated to the market participant for defined period of time, for example, five years. After that period of time, market participants would be required to participate in the capacity allocation process at relevant entry/exit points on the same basis as all other users on the system.

Existing holders of AMDQ and AMDQ cc would be charged the relevant reference tariff for their allocated level of capacity. On the basis that market participants holding AMDQ and AMDQ cc are currently subject to volumetric charges for use of the DTS, they would also be subject to pay at least the applicable reference tariff for capacity allocated at the relevant entry/exit point (as noted in the next chapter, the current volumetric tariffs will be replaced with capacity tariffs under the new system).

There are a number of additional matters to consider when designing the transitional arrangements for AMDQ and AMDQ cc, including:

- how price signals would be maintained at entry/exit points where auctions are used to allocated capacity, but where some market participants are eligible for an automatic allocation of capacity based on their AMDQ/AMDQ cc allocation;
- the duration of the automatic allocation of entry-exit capacity rights, noting that AMDQ cc are generally allocated on a five-yearly basis, and AMDQ were allocated on an enduring basis; and
- how the existing injection-linked nature of AMDQ should be acknowledged in a system of entry and exit rights.

The Commission is interested to hear the views of stakeholders on each of these points, as well as on any additional concerns relating to the transition of the existing, albeit limited, benefits afforded to market participants holding AMDQ and AMDQ cc.

Box 4.3 Stakeholder questions

The Commission welcomes stakeholder views on any of the issues raised in this chapter. In particular, we are interested in the following points:

- Whether integrated auctions are the most appropriate mechanism to allocate existing (and trigger new) baseline capacity at production entry points, interconnection entry/exit points and storage entry/exit points. What are the likely challenges in developing and applying an auction mechanism in this context?
- Whether an auction mechanism, combined with a bilateral planning process between APA and directly connected customers, is the most appropriate mechanism to allocate existing (and trigger new) baseline capacity for exit points relating to large customers directly connected to the DTS. What are the likely challenges in developing and applying these mechanisms?
- Whether automatic allocation of capacity, combined with a bilateral planning process between APA and distributors/retailers, is the most appropriate mechanism to allocate existing (and trigger new) baseline capacity for distribution exit points. What are the likely challenges in developing and applying these mechanisms?
- Having regard to the Commission's preliminary view on options for allocating capacity, how the matter of transitioning the existing, albeit limited, benefits afforded to market participants holding AMDQ and AMDQ cc could be addressed under the proposed Southern Hub.

5 Capacity pricing and revenue at the Southern Hub

This chapter considers a number of matters relevant to the revenue and pricing arrangements under the Southern Hub model. It outlines the existing framework for the regulation of pipeline services and considers how the new market design would fit within this framework. It then outlines the general process for setting tariffs in entry-exit systems and compares this to the process currently used to set tariffs in the DTS.

5.1 Regulation at the Southern hub

The National Gas Law (NGL) and National Gas Rules (NGR) apply economic regulation to covered pipelines. There are two types of regulation for covered pipelines - light regulation and full regulation. The Victorian DTS is subject to full regulation and, as such, the NGL requires APA as the DTS service provider to submit an access arrangement to the AER, and periodically revise it.[59]

The DTS access arrangement sets out the terms and conditions under which third parties can use the DTS. It must specify at least one reference service that a significant part of the market is likely to seek, and a reference tariff for that service.

The NGR provide the AER with some discretion in deciding whether pipeline services that are sought by a significant part of the market should be classified as reference services.[60] Where they are not, the AER would not be required to set a reference tariffs. This discretion provides the AER with flexibility in determining the appropriate regulatory treatment of gas pipeline services and is intended to be used in circumstances where setting a reference tariff may result in a tariff that may not be reflective of the efficient costs of providing that service to users.[61]

Entry and exit rights would meet the underlying policy intent for the definition of a reference service: that is, they are likely to be sought by a significant part of the market. This implies there is a need for some regulatory oversight of providing the service. Where the regulator is able to determine a tariff reflective of the efficient costs of providing the service, a reference tariff would also be set.

59 The revisions generally occur once every five years as scheduled reviews, but can occur more frequently — for example, if a trigger event compels an earlier review, or if the service provider seeks a variation to the access arrangement.

60 This discretion was given to the AER in a rule change made by the AEMC in 2012. The AEMC amended the definition of reference services to provide regulators with greater flexibility in determining the appropriate regulatory treatment of gas pipeline services. The final rule allows prices for regulated services to be set at levels that are more efficient and cost reflective .See AEMC 2012, *Reference service and rebateable service definitions*, Rule Determination, 1 November 2012, Sydney.

61 For example, where there is a high level of uncertainty with respect to revenue and/or demand for the pipeline service.

However, there is uncertainty around how this would operate in practice. As set out in Box 5.1, the regulatory framework for gas pipelines does not differentiate between the contract carriage and market carriage models for managing capacity on transmission pipelines. This has caused some friction where aspects of the different market designs have not fitted comfortably within the framework. While the entry-exit system may be able to be accommodated within the existing framework, there is a question around whether there would be benefit in establishing a specific framework for the regulation of pipeline services offered within a virtual hub.

Box 5.1 Impact of market design on pipeline services and revenue

The NGL does not differentiate between the contract carriage or market carriage models for managing capacity allocation on transmission pipelines.

For contract carriage pipelines, it is reasonable to expect that the reference service will be a 'firm' (or 'non-interruptible') service and that payment for that service will reflect both the reservation of pipeline capacity as well as the actual flow of gas. This reflects that ‘firm’ services are demanded by a significant part of the market and most gas pipelines are founded on the basis of long term contractual arrangements based on the right to use a certain reserved amount of pipeline capacity.

In contrast, the Victorian DTS is a market carriage pipeline and the reference service is a 'non-firm' service. In addition, and to reflect the operation of market carriage, users pay the reference tariff as they use the pipeline system. While users have not required contracts or needed to reserve capacity to use the Victorian DTS, their usage of the pipeline is not guaranteed. Users that hold AMDQ or AMDQ cc do have rights that are analogous to some rights that can be found in contracts. In the 2013 DTS access arrangement, the AER classified AMDQ cc as a reference service such that the revenue derived from the sale of this right is, for the current access arrangement period, also regulated.[62]

Transitioning the current market carriage arrangements to an entry-exit system for capacity allocation will introduce the concept of firm capacity rights to the DTS by allowing users to book capacity rights at each entry and exit point to the system. As discussed in Chapter 3, the baseline quantity of entry and exit capacity rights would be offered to market participants on a firm basis, and payment for the rights would reflect the reservation of capacity.

62 This classification was made on the basis that AMDQ cc are sought by a significant part of the market.

5.2 Capacity pricing at the Southern Hub

5.2.1 Setting tariffs at entry and exit points

In entry-exit systems, the following steps are generally followed to set tariffs at entry and exit points on the system:

1. The regulator determines the pipeline owner's allowed revenue. This is usually determined by a combination of depreciation, return on capital and operating costs.

2. A forecast is made for capacity/throughput demand for each entry and exit point over the regulatory period and also in some cases the distance that the gas will travel.

3. The costs that must be recovered from each entry and exit point is then determined. The process of allocating costs that must be recovered from groups of entry and exit points is referred to as cost allocation.

4. The reference tariff at each entry and exit point is determined. Often, this is done simply by dividing the costs allocated to that point by the capacity/expected demand at that point (or group of points).

There are many ways to undertake the cost allocation process in step 3 above. The different approaches and design choices can produce very different tariffs for the same set of allowed costs and forecast demand. The key design choices relevant to the tariff regime for the Southern Hub are considered below.

The entry-exit split

In designing the tariff regime for the Southern Hub, the split between the revenue to be recovered from entry points and the revenue to be recovered from exit points will need to be determined. The appropriate split will depend to some extent on the choice of cost allocation methodology. In addition, the allocation of costs between entry and exit points has implications for the cost reflectivity of the resulting tariffs, and hence also for investment signals.

The natural starting point for the entry-exit system at the Southern Hub would be to split the revenue requirement 50:50 between entry and exit points. This split is the generally accepted approach adopted in European entry-exit system.

The capacity-commodity split

In gas transmission, costs are usually influenced by either the quantities of gas transported, or by the booked capacities. Where costs are influenced by transported gas quantities, it may be appropriate to design and apply a commodity charge which would be levied on actual usage or throughput (that is, an amount per volume unit consumed).

Alternatively, where costs are influence by booked capacities, it may be appropriate to design and apply a capacity charge. These charges are levied against a user's entitlement to use the network (the entitlement would generally be expressed in terms of a maximum daily rate reserved by the user, either in volumetric or energy terms). Typically, fixed costs should be recovered by the capacity charge and variable costs by the commodity charge.

Under the Southern Hub model, the majority of APA's revenue requirement would be recovered via capacity charges at entry and exit points. However, depending on the form of regulation applied to APA (revenue or price cap), it may also be necessary to include a volumetric tariff in order to account for any under- or over-recovery of revenue from the sale of capacity, over time.[63]

Locational differentiation

In entry-exit systems, tariffs may be applied based on either: a uniform approach (postage stamp tariffs), where tariffs for different entry and exit points are set equally; or locational differentiation, where the tariffs differ for every entry and exit point or zone. An obvious reason for differentiating tariffs is to achieve cost-reflective tariffs. In this case, tariffs are set for the different entry and exit points through various cost allocation methodologies which use different drivers in allocating cost to network sections (for example, pipeline length, technical capacity, replacement costs). These methodologies may also utilise marginal cost pricing or average cost pricing.

Further, and to reduce the complexity of tariffs, the DTS is currently divided into 25 withdrawal zones. Users are charged on the basis of their measured withdrawals within the specific zones. As noted in Chapter 4, there are over 110 exit points on the DTS where parties can withdraw gas from the DTS. There may be benefit in continuing to structure exit tariffs on a zonal basis given the practicalities of charging separate prices for each of the individual exit points as well as the inability to effectively create locational signals at these points.

Product/customer differentiation

Tariffs applied to network points may be differentiated. For example, different tariffs can be applied to capacity products with different durations (for example, daily, monthly, quarterly, annual). In addition, tariffs can be applied users based on the specific characteristics of the connected party. Characteristics may include annual consumption, delivery pressure or gas quality.

Under the proposed entry-exit system, APA would recover its allowed revenue through the sale of baseline capacity products. The products and durations should be developed to meet the needs of the market. Decisions on tariffs for the different products will need to be made as the model is developed further.

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63 For example, if auctions are consistently above the reserve price, but not high enough to trigger new capacity, then this surplus revenue would be returned to users of the DTS via decreased variable charges.

5.2.2 Framework for setting transmission tariffs

Rules 92-93 and 95-97 of the NGR form the framework for setting transmission tariffs for the DTS. Once total revenue (total costs) of the pipeline has been determined, it needs to be allocated between reference services and the other services provided by the pipeline.[64]

Once these costs are allocated, reference tariffs are calculated with the relevant demand information. A reference tariff should recover the costs incurred in providing that reference service and be allocated amongst the relevant users.[65]

The methodology for the allocation of costs, the relationship between costs and tariffs for services and any pricing principles used but not disclosed elsewhere, must be included in the DTS access arrangement information, as part of the proposed approach to setting tariffs.[66]

In addition to the general allocation rules, the NGR sets out a number of specific cost allocation requirements relevant to transmission pipelines. A reference service for a transmission pipeline must:[67]

- be designed to reflect the relative revenue referable to the reference service and that revenue is allocated between users or a class of users of the reference service.
- reflect total revenue for the reference service which comprises direct costs for the reference service and other costs. These costs need to be consistent with the revenue and pricing principles, and
- allocate revenue for a reference service to a user or class of users that reflects direct costs and other costs (consistent with the revenue and pricing principles) referable to the user or class of users.

A key question to consider is whether the current pricing framework is sufficient to deliver the outcomes intended by the introduction of the entry-exit system. For example, how the pipeline services introduced under the entry-exit regime would fit within the existing reference service framework will need to be considered. This is important because it has implications for the level of regulatory oversight given to tariffs for those pipeline services. This issue is discussed further in section 5.2 below.

In addition, whether the existing principles and allocation rules set out in the NGL and NGR are sufficient to guide the development of tariffs for entry and exit capacity under the proposed Southern Hub is also matter that requires further consideration. It may be

64 That is: costs directly attributable to reference services would be allocated to those service; costs directly attributable to pipeline services that are not reference services are to be allocated to those services; and other costs are to be allocated between reference and other services on a basis approved by the AER and consistent with the revenue and pricing principles service.

65 Subject to the use of prudent discounts as provided under NGR rule 96.

66 NGR rule 72(1)(j).

67 NGR rule 95.

necessary to design a new set of pricing principles applicable to pipeline services offered within a virtual hub (as distinct from services offered on pipelines outside of the virtual hub). The objective is to ensure the process for setting tariffs is transparent and that complexity of the price setting process is minimal under the new market design.

5.2.3 Setting reserve prices at entry and exit points

Where entry and exit capacity is auctioned,[68] the tariffs determined through the regulatory-led process could be used as the reserve price for these auctions. The reserve price for each auction is the minimum price at which any market participant must bid in order to obtain capacity. When there is more capacity available than demand at a certain entry or exit point, bids for capacity will be satisfied at the reserve price.

At a high-level, the suite of entry and exit reserve prices across the system should be set with the expectation that they will recover the costs APA is allowed to recover by the AER. In practice, there are a number of considerations that will need to be taken into account in setting these reserve prices, including:

- whether multipliers should be applied to standard products with different durations;
- the setting of reserve prices for interruptible capacity products (as opposed to firm capacity products) and how this would be returned to the market; and
- whether the zonal nature of tariffs is to be retained, or whether every point will receive a unique tariff.

The reserve price would also be determined through a regulatory-led process.

Box 5.2 Stakeholder questions

The Commission welcomes stakeholder views on any of the issues raised in this chapter. In particular, we are interested in:

- Whether the pricing and revenue arrangements required by an entry-exit system can be accommodated within the existing framework for the regulation of gas pipelines, or whether changes to that framework need to be considered.

68 As is proposed for: all production entry points; interconnection entry and exit points; storage entry and exit points; and exit points relating to large customers directly connected to the DTS.

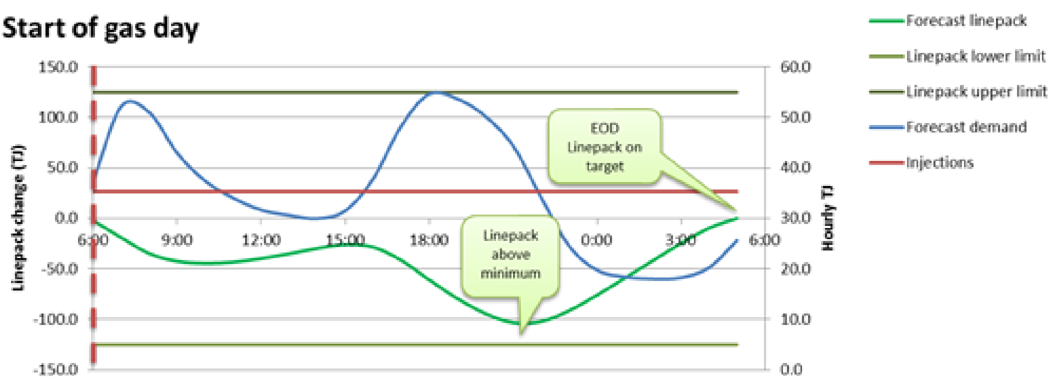
6 Balancing at the Southern Hub

Balancing is an integral part of a physical gas market because injections into the system must over time equal withdrawals, so that pressures remain within operational limits. Often a large portion of demand is uncontrollable (that is, residential customers), which means that actual gas consumption on any given day could be above or below what shippers' forecast, and therefore lead to imbalances.

When shippers are out of balance during a gas day, this changes the quantity of gas stored in the pipeline (known as linepack): when withdrawals exceed injections, the linepack will decrease (and vice versa). The degree to which linepack can absorb system imbalances depends on the capacity of the pipeline system and the shape of injections and withdrawals over a specific time period.

As can be seen in Figure 6.1, linepack absorbs the fluctuations in demand throughout the day, as gas injections into the system generally occur at a constant rate. Where the upper and lower limits are close together and demand is highly variable, it may be necessary for the system operator to restore the balance of the system at regular intervals throughout the day. Where the opposite is true, this might only need to be done once every 24 hours or so. Accordingly, the balancing approach at the Southern Hub has to take account of the physical characteristics of the Victorian DTS.

Figure 6.1 Illustrative example of linepack management



AEMC analysis.

In addition to system security, the balancing period can have implications for the development of trading liquidity and competition, and a number of trade-offs around balancing market design need to be considered. These are discussed in this chapter, along with financial incentives for shippers to remain in balance and the procurement of balancing gas by shippers and AEMO, as the system operator and residual balancer.

Exchange-based trading with entry/exit capacity allocation is the predominant market design in Europe, where the gas systems most closely resemble the Victorian DTS. Some of these markets have witnessed substantial increases in trading liquidity in recent times and the Commission is interested in understanding and applying these lessons to the Southern Hub, where appropriate. For this reason, we have reviewed the balancing regimes of Britain and the Netherlands, and held teleconferences with National Grid and Gasunie to understand the differences and similarities between our respective markets.

The final part of this chapter sets out two balancing approaches and seeks views from stakeholders on the one that should be developed more fully through the detailed market development process, if the Commission's gas reform package is agreed to by the Energy Council. The two options can be categorised as:

1. continuous market-based balancing; and
2. fixed period market-based balancing.

6.1 Balancing regime principles and characteristics

The Commission considers that balancing at the Southern Hub should:

- support system security as the highest order priority;
- be competitive and market-based, so that balancing actions are achieved at least cost;
- be transparent and non-discriminatory, so that all shippers can compete on a level playing field;
- apply cost-to-cause incentives (where appropriate), so that risks are allocated appropriately and each shipper bears responsibility for its actions; and
- prioritise a simple but effective approach that traders can easily understand and that could potentially be adapted to the Northern Hub in the future.

A market-based gas balancing regime for a virtual hub can be considered to have the following components:

- **Primary system balancing**: where each shipper is incentivised to balance its own system injections and withdrawals; and
- **Residual system balancing**: in the event that network users are not collectively balancing their injections and withdrawals sufficiently, AEMO can take actions to rectify the imbalance.

Primary system balancing provides incentives for shippers to balance their injections and withdrawals, thereby minimising AEMO's role in keeping the system in-balance. This reflects a view that shippers are best placed to manage their portfolios efficiently. Facing the risk of imbalance charges that would be designed to cover the costs of AEMO's actions, shippers have an incentive to use all the tools at their disposal to manage their portfolio positions at least cost.

Under the Southern Hub model, AEMO would ultimately be responsible for system security through its role as the residual balancer. The residual balancer acts to restore system linepack to the required level if shippers are unable to balance their own positions and system security is under threat.

If shippers are collectively unable to restore the system balance and AEMO, through its residual balancing role, is required to take action, the costs of doing so would be recovered from shippers on a cost-to-cause basis. Shippers out of balance would face a charge based on the market value of the balancing gas. This provides an incentive for shippers to stay in balance.

Within the primary and residual system balancing model, there are a number of market design aspects that need to be determined, including:

- entry and exit point nominations;
- balancing period;
- balancing incentives; and
- procurement of balancing gas.

A description of these market design characteristics is below.

6.1.1 Entry and exit point nominations

AEMO and shippers need an accurate account of the physical system throughout the gas day for the hub to be kept in balance. For this to occur, shippers will need to inform AEMO of their nominations into and out of the virtual hub, and any trades that occur. Shippers will need to nominate to AEMO gas:

- entering the Southern Hub transmission system, specifying the entry point, date, profile and quantity;
- exiting the Southern Hub transmission system, specifying the exit zone/point, date, profile and quantity; and
- traded at the Southern Hub virtual point whether via the exchange or over-the-counter (OTC), specifying the date and quantity.

Figure 6.2 shows the imbalance equation at the virtual hub. Entry quantities are volumes of gas entering the system from production and storage sources within the hub, as well as from interconnected pipelines. Exit quantities are demanded volumes within the hub, including injections into storage, as well as gas exiting the hub through interconnected pipelines

Figure 6.2 Matching injections and withdrawals

AEMO needs to be advised of trading purchases and sales that occur on the gas day so that shippers are not inadvertently penalised for being out of balance. For example, Shipper A may have purchased additional gas from Shipper B on the gas day to offset an increase in demand. If AEMO is not notified of this transaction, it sees that Shipper A withdraw more gas than it nominated.

Nomination estimates would also be provided to AEMO ahead of the gas day, as is currently the case for the DWGM. This allows AEMO to configure the gas system so as to minimise overall system operation costs, as well as assess whether capacity additional to the baseline can be offered to the market, based on load flow modelling.

6.1.2 Balancing period

As discussed above, the balancing period is the time over which injections and withdrawals are required to be balanced by shippers. Selection of the balancing period depends on linepack, while the degree of linepack flexibility depends on the physical characteristics of the network, in particular the diameter and length of the pipelines, entry and exit pressures and gas composition.

At the end of the balancing period, arrangements to settle the costs of managing imbalances incurred by the system operator are passed onto market participants who have not matched their injections with their withdrawals. There is an inherent trade-off with selecting the balancing period - a shorter period can make balancing actions expensive and create a barrier to entry, while a longer period is more likely to result in the costs incurred by the system operator being smeared across all shippers, weakening incentives on shippers to take action to balance their own portfolios.

The majority of European gas markets have a daily balancing system in place where imbalances are settled at the end of a 24 hour gas day. The desire to promote market entry led the European Union to adopt this requirement, as it was considered an appropriate trade-off between the efficiency benefits of accurate targeting of balancing costs and the benefits of encouraging market entry by not imposing unduly onerous requirements.[69]Although, we note that the Netherlands has a unique regime where balancing is undertaking continuously and a shipper's imbalance is only relevant if the total system is out of balance.

Strengths and weaknesses of various balancing periods are set out in Table 6.1.

69 FTI, *Conceptual Design for a Virtual Gas Hub(s) for the East Coast of Australia*, December 2015, p. 79.

Table 6.1 Options for balancing period selection

Balancing period	Advantages	Disadvantages
Intra-day - participants are cashed out at certain periods within the day (eg, every 4 hours).	Strengthens price signals and can generate liquidity in intra-day gas trading. If the market is sufficiently liquid, it should minimise the hub operator's role. If the hub operator is required to intervene, the costs of doing so can be allocated to those that cause the imbalances.	Requires that balancing be conducted over a relatively short time frame, which can create a barrier to new market entry, particularly in the absence of a liquid hub. The potential costs to new entrants in managing potential imbalances, or facing charges for failing to do so, may outweigh any benefits of efficient price signals. Requires complex arrangements for trading of linepack.
Daily - participants are cashed out once during the day.	Encourages trading within the day and allows new entrants time to balance their portfolios.	If imbalances arise during the gas day, these are managed by the system operator and costs are shared among market participants.
Continuous balancing period - shippers' imbalance positions are only relevant if the overall system is out of balance.	Efficient in that it allows shippers to retain certain imbalances if it is not causing an imbalance in the overall system. Promotes market entry by avoiding balancing requirements when not strictly necessary.	May require operational change for pipeline operators and shippers in monitoring the balance in the system as well as shippers individual positions.

Source: AEMC and FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 72-73.

6.1.3 Incentives to remain in balance

If market participants are unable to balance their injections and withdrawals, AEMO will be required to take action through its role as the residual balancer. In addition to utilising linepack and running compressors, AEMO could call on the following tools to protect system security:

- buying additional gas to bring onto the system where, collectively, shippers are short, ie, have not procured enough gas to meet demand;
- selling excess gas from the system linepack where, collectively, shippers are long, ie, have sourced too much gas;
- scaling back interruptible entry and exit capacity, to reduce the flow of gas into and out of the system;
- buying back firm entry and exit capacity;

- calling on directly contracted services, such as storage; and
- as a last resort, directing shippers to modify their injections and withdrawals.

Some of these tools are location-specific in order to resolve linepack issues at specific sections on the network, while others are generic across the whole system. Both segment and system linepack are relevant to AEMO, because while the system may have total linepack above the minimum level, a pipe segment may have linepack below minimum levels.

The general principle applied is that the costs incurred by AEMO should be passed on to the shippers with imbalances so that they are compensating the operator for having had to buy or sell gas on their behalf. The imbalance charges are based on the costs of the AEMO's trades and can be set as:

- the **average cost** of all the purchases or sales of gas taken by AEMO in order to balance the system; or
- the **marginal cost** - the highest price paid by AEMO to buy additional gas (or received for selling excess) gas during the balancing period.

It is important when determining the strength of these incentives that consideration is given to the fact that new entrants may be deterred from participating in the market if the incentive to remain in balance is set too high.

AEMO's role would require it to publish a guideline setting out the procurement principles and tools it will use in its residual balancing role. AEMO would also be required to publish a report setting out any residual balancing actions taken and the associated costs.

6.1.4 Procurement of balancing gas

Balancing gas could be procured by AEMO through within-day spot market products on the Southern Hub exchange. In this manner, market-based balancing enables cost reflectivity of AEMO's actions by relating the cost of such actions to the market price of the commodity during any given balancing period. This approach has been implemented in Great Britain and the Netherlands, as discussed below.

Where a wholesale gas market is not yet workably competitive and trading is illiquid, a separate balancing platform could be developed for procuring gas to balance the hub. This mechanism could be similar to the STTM Market Operator Service, where participants provide offers for additional gas they can inject and withdraw from the hub. On the gas day AEMO can use the balancing stack to buy or sell imbalances as required.

The Commission notes that a key drawback of a separate balancing platform would be the consequential reduction of trading liquidity on the Southern Hub exchange. This is because gas that is offered on the balancing platform cannot be simultaneously offered on the exchange. Conversely, the requirement to trade balancing products on the exchange contributes positively to spot market liquidity and the overall development of the market.

6.2 International balancing models

The Commission has looked at two international balancing models in detail and had discussions with the respective system operators: These are the:

1. Gas Transport System (GTS) in the Netherlands operated by Gasunie; and
2. National Transmission System (NTS) in Britain operated by National Grid.

6.2.1 Dutch GTS[70]

The GTS has a unique regime where there is no defined balancing period - balancing occurs continuously. Shippers are provided with close to real time information that allows them to consider the costs of restoring any portfolio imbalance with reference to the imbalance of the total system. This promotes the efficient utilisation of linepack when there is flexibility in the system and the efficient restoration of the system balance when imbalances occur.

Gasunie, the system operator, is the residual balancer responsible for system security. In this role it can buy and sell gas on the spot market to restore the system balance if shippers are collectively unable to. As a last resort, Gasunie can direct shippers to modify their injections and withdrawals.

Nominations

Nominations are submitted to Gasunie to indicate how much gas shippers wish to transport for each hour of the gas day at a network entry/exit point. Nominations are tested against the capacity booked by each shipper. If nominations are higher than booked capacity, then shippers are notified and the nomination is potentially rejected.

Gasunie must be informed of initial nominations before 2pm on the gas day prior to the gas day on which transport is to take place, although nominations can be made up to179 days in advance. Shippers receive confirmations by 6pm before the gas day. Renominations are possible if these have been received and accepted at least 2 hours before the first hour of the proposed change in gas flows.

When a trade takes place on the TTF virtual point, shippers notify Gasunie and there is a 30 minute lead time that applies before the nomination is actioned.

70 This section is based on information published on Gasunie's website: https://www.gasunietransportservices.nl/en/

Balancing period

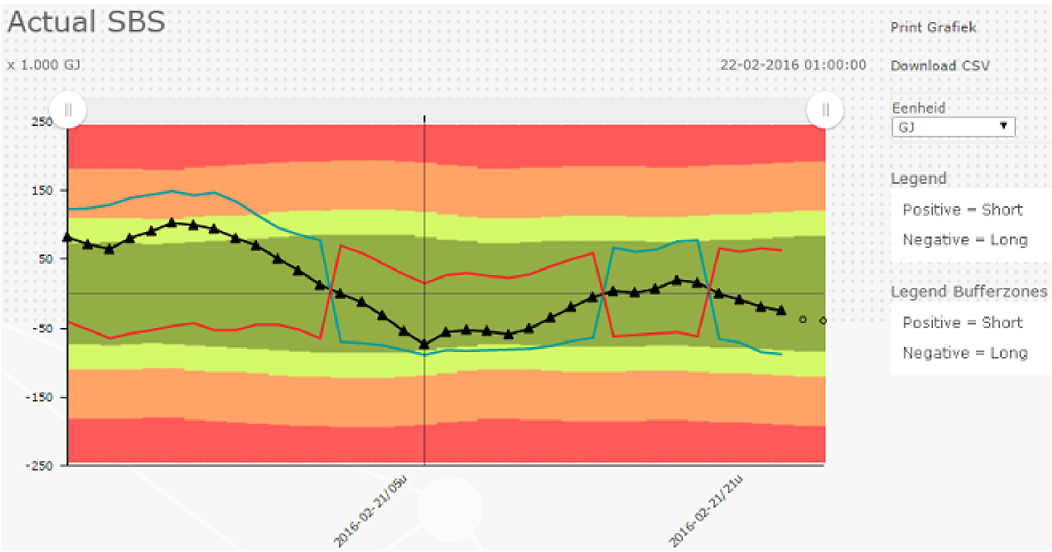
As discussed above, there is no fixed balancing period for the GTS. This means that a shipper's long or short position can remain that way without incurring penalties for a period of time as long as the system linepack is within operational pressures.

The regime uses actual and estimated near real-time information provided to shippers to enable them to balance their portfolios on a continuous basis 24/7. As long as the System Balancing Signal (SBS), as shown by the black line in Figure 6.3, remains within the dark green zone, the system operator will not take balancing actions towards any shippers.

Figure 6.3 is the actual system balancing signal taken from Gasunie's website. The black line indicates the total system pressure, while the coloured segments represent four zones - green being stable and red being an emergency. The red line represents 'helpers' whose actions are contributing to keeping the system within the dark green zone, while the blue line indicates 'causers' who actions are pushing the system out of balance.

If a shipper has an imbalance at 6am at the start of the next gas day, but the overall system is within the dark green zone, they are deemed to have used the linepack flexibility service. Shippers are charged a nominal tariff for the use of this service.[71]No gas is exchanged between the system operator and the shipper, and the shipper's imbalance position is carried forward for the new gas day.

Figure 6.3 GTS System Balancing Signal



Source: Gasunie Transport Services website.

71 The nominal tariff is generally set at 0.4 per cent of the neutral gas price, which is the volume weighted average of all trades executed on a specific day.

As can be seen in Figure 6.3, the four zones are symmetrical whereby the same flexibility exists whether the system is long or short gas. The dark green zone represents 70 TJ of linepack flexibility in one direction, while the dark green and light green zones represent a total of around 107 TJ. As the SBS enters the light green or orange zones and is expected to remain in the zone, Gasunie will begin purchasing gas if shippers are not taking individual action to respond (as discussed below).

While further analysis and modelling needs to be undertaken, the Commission understands that, on most days, the level of linepack flexibility in the DTS may be similar or slightly greater than that in the Dutch system represented above. The Commission is working to understand how similar zones would be estimated for the DTS and therefore the level of linepack flexibility available to shippers.

Incentives to remain in balance

Linepack flexibility is divided into four zones, as shown in Figure 6.3:

- **Dark green zone**: as long as the operational limits remain within the dark green zone, no action is taken.
- **Light green zone**: if the system enters or remains in the light green zone, a balancing action may be performed under certain circumstances.
- **Orange zone**: if the predicted system enters or remains in the orange zone, a balancing action will be performed.
- **Red zone**: if the predicted system enters or remains in the red zone, a balancing action must be performed.

Gasunie publishes the size of the zones for each hour of the gas day at least two hours before the start of each gas day. This is because the flexibility of the system changes throughout the day in response to shippers' nominated injections and withdrawals at entry/exit points. Once the hourly values have been published, they do not change for the remainder of the gas day.

We note that to conserve linepack, Gasunie requires shippers supplying small customers (uncontrollable demand) to apply a 'damping' formula. This results in the profile of gas entering the system more closely following the profile of gas being withdrawn. Under this approach there is greater usable linepack available (larger dark green zone) than if gas was injected at a constant rate (as shown in Figure 6.1).

Throughout the day shippers receive near real time information similar to Figure 6.3 updating them on the total system balance. Each hour they also receive information on individual portfolio positions. Shippers are then able to make decisions around whether they need to take physical or commercial actions to resolve any imbalances and the most efficient way to so. In this sense, shippers are able to continuously trade throughout the day to buy and sell additional gas to resolve any portfolio imbalances (and therefore contribute to the overall system balance).

As shippers can see the total system imbalance and their own individual position, they can trade-off any likely balancing actions by Gasunie (as the residual balancer) with the costs of taking action to restore their own portfolio imbalance. For instance, on a day where the total system is within the dark green zone, but a shipper is out of balance, it may not need to purchase spot gas on the exchange as Gasunie is unlikely to be required to take action. The shipper may instead choose to inject an additional amount of gas the following day to return its portfolio imbalance to zero.

Information provision

Provision of total system balance and individual portfolio imbalance information are critical components of the Dutch balancing regime. The quality of information, from metering to information provision, is one of the most important aspects of the balancing process. Gasunie collects metering data and runs sophisticated allocation processes to achieve this.

For all network points other than at distribution networks, near real time data is generally available directly to Gasunie or via third parties. Allocations are based on flow information and a connection register at each point. Determining allocations for distribution connected users is based on a generalised load profile informed by historical annual consumption and effective daily temperatures.

As the near real time balancing information shippers are responding to may not always be exactly accurate, a process is in place for reconciling any unders and overs once more accurate meter data is received. Around one month after the gas day, a settlement advance of any outstanding imbalances takes place on the basis of a "neutral gas price" and has no effect on the allocation and settlement of imbalance gas in near real-time.[72] Further reconciliation also takes place as more accurate data is processed (around four to five months after the end of month).

Gasunie considers that this simplification is essential for keeping the administrative process manageable. Balancing is a near real-time operational process, based on near real-time information. Gasunie considers this justifies settlement of imbalances on the basis of operational information, as at the moment of acting to stabilise the system, no other information is available.

Procurement of balancing gas

Balancing actions taken by Gasunie are automated and carried out in a transparent manner on the ICE-ENDEX exchange. When residual balancing actions are required to be taken, Gasunie publishes a market notice and places a request for quote on the exchange. Gasunie purchases two types of exchange-traded products depending on the colour of the zone the system is in:

72 The Neutral Gas Price is the volume-weighted average price of all trades executed in contracts which deliver on a specific gas day and is published on ICE-ENDEX here: https://www.theice.com/marketdata/reports/168

- **Balance-of-day product**: in the light green zone Gasunie will buy or sell balance-of-day products. This means that gas is injected/withdrawn at a constant rate until the end of the gas day with effect from four hours after the hour of the trade, ie: if the product is purchased at 8am, gas will flow from 12noon until the end of the gas day.

- **1-hour product**: in the orange or red zones Gasunie will buy 1-hour products. Gas is injected/withdrawn over one hour from the next hour following the trade.

Gasunie orders the volume of gas expected to restore the system to within the dark green zone. The gas that is injected/withdrawn as a result of Gasunie's balancing actions is assigned pro rata to the causers on the basis of their cumulative portfolio positions of the hour that balancing gas is called. The price charged to the causers is the **volume-weighted average price** of the gas bought/sold.

If Gasunie does not expect shippers' balancing actions to be sufficient to maintain system security, it is able to instruct shippers to change amounts injected at entry points and – as a last resort – withdrawals at exit points. Shippers therefore have an incentive to offer balance-of-day and hourly products on the exchange to avoid operator-directed outcomes that may adversely impact their commercial positions.

6.2.2 British National Transmission System[73]

In contrast to the Dutch system, balancing on the NTS is undertaken over a fixed period of 24 hours. This means that at the end of the gas day shippers' imbalanced quantities are settled at the system marginal sell or buy price. These prices are based on the price of any residual balancing actions taken by National Grid, the party ultimately responsible for system security.

Nominations

Nominations to National Grid are made through the Gemini system, which is jointly owned by the five major gas distribution network companies and National Grid's gas transmission business in the Britain. Gemini also facilitates entry and exit capacity bookings and transfers, amongst other things.

Shippers nominate the quantities of gas to inject/withdraw from the NTS each day to enable National Grid to plan and operate the system and undertake operational balancing. Nominations are made between 1pm and 2.30pm the day before the gas day. Re-nominations then start from 3pm.

73 This section is based on information published on National Grid's website: http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/

Balancing period

As noted above, the balancing period for the NTS is one gas day or 24 hours. Over this period shippers are provided with information from National Grid on the total system balance and are able to undertake balancing actions in response to this information.[74] National Grid does not provide shippers with information on their individual portfolio positions during the gas day.[75]

If the system is moving outside of its operational limits during a gas day, National Grid is able to take actions in accordance with the Uniform Gas Code and its System Management Principles Statement to restore system pressures. This is discussed further below.

Incentives to remain in balance

National Grid does not apply within-day obligations on shippers, other than some restrictions around complying with notice periods when changing gas flow rates. Shippers are actively incentivised to stay in-balance to minimise the actions taken by National Grid, for example:

- if a shipper at the end of the day has injected too much gas in an over-pressured system, they will receive the system marginal sell price, which is below the average of the within day deals on the market; and
- if a shipper has injected too little gas in an under-pressured system, they will receive the system marginal buy price, which is higher than the average of the trades.

Conversely, National Grid rewards shippers that are 'helping' to keep the system in balance. Shippers who at the end of the day injected gas above their obligations in an under-pressured system are rewarded as are shippers who injected gas below their obligations in an over-pressured system.

Procurement of balancing gas

To ensure that shippers can respond to the above incentives, National Grid posts the pressure of the system to all shippers frequently throughout the day. This allows shippers to either utilise their own physical positions and/or trade on the spot market to rectify their imbalances, which may be more cost efficient than their imbalances being settled at the end of day system marginal prices.

Similar to the GTS, National Grid has outsourced the operations of the spot market, referred to as the On The Day Commodity Market (OCM), to ICE-ENDEX. Within-day, day-ahead and other products are offered on a continuous trading exchange similar to

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74 See: http://www2.nationalgrid.com/UK/Industry-information/Gas-transmission-operational-data/

75 The first information provided to shippers occurs the day after the gas day.

the Wallumbilla gas supply hub that allows shippers and National Grid to balance the system. The OCM is operational 24/7 for shippers and National Grid.

When the system becomes too over- or under-pressured, National Grid also has the option to rectify imbalances by buying or selling gas on the spot market. It can do this through a range of tools and faces regulatory incentives as the residual balancer to do this efficiently.[76] The tools National Grid has at its disposal for managing a whole-of-system balancing requirement include:

- buying or selling gas on the OCM (including locational gas products);
- buying or selling gas on the over-the-counter bilateral market; and
- calling on operating margins gas (pre-existing contracts National Grid holds with storage providers, LNG import facilities, shippers etc).

We noted that, in addition to acting as the residual balancing, National Grid is responsible for operating the gas system and managing congestion. Localised congestion can arise on a gas network when physical flows change in a way that the system cannot accommodate. This can occur when the commercial incentives on shippers change at short notice. To deal with this issue, National Grid employs the following measures in addition to those above:

- scaling back of off-peak exit capacity;
- buying back firm exit and/or entry capacity;
- scaling back of interruptible entry capacity; and
- flow swaps.

The tools National Grid employs for any given event are influenced by the financial implications of the regulatory incentive arrangements and any requirement to achieve timely gas flow rate changes. Generally they are used close to the time of gas flow, but can also be used ahead of the gas day if National Grid considers this is likely to reduce the risk and cost of future actions.

National Grid has the final responsibility for managing any residual system imbalance and ensuring that system security is maintained.

6.3 Southern Hub balancing options

This section discusses the characteristics of the DTS and potential benefits and costs of implementing a continuous or fixed period balancing regime at the Southern Hub. It also sets out the Commission's proposed approach for the balancing workstream.

76 As National Grid is a for-profit regulated entity, financial incentives are applied through the regulatory framework that aim promote efficient behaviour.

Based on the Commission's preliminary analysis, there does not appear to be any unique attributes of the DTS that would prevent continuous or fixed period balancing being implemented at the Southern Hub. Notwithstanding this, for reasons set out below the Commission considers that a continuous balancing approach is likely to result in more efficient outcomes than a fixed period.

For completeness, Box 6.1 summarises how balancing currently takes place in the gross pool DWGM design.

Box 6.1 How balancing takes place in the DWGM

The DWGM is a gross pool market design. This means that each day market participants are required to submit bids and offers to withdraw and inject gas into the DTS, respectively. AEMO matches supply with demand and schedules the market based on the lowest price required to meet all demand.

When participants' injections and withdrawals do not follow AEMO's schedules during each of the five daily intervals, they are out of balance and will face deviation payments. Deviation payments are calculated at the next scheduled price. In this sense, the DWGM has an intraday balancing mechanism, whereby participants' imbalances are settled at the 6am, 10am, 2pm and 6pm daily schedules.

Currently, participants do not find out the magnitude of any deviation payment until 123 business days after the gas day. Further, if ancillary payments were required on a given gas day, participants who deviated and were out of balance may also be liable to pay uplift charges.

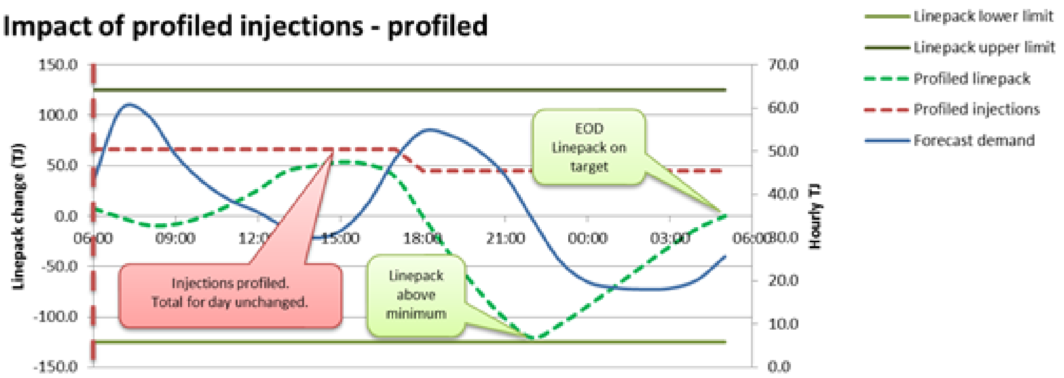
6.3.1 Physical characteristics of the DTS

As discussed in Chapter 4, the DTS has nine controllable injection points, five controllable withdrawal points, 12 uncontrollable withdrawal points to transmission customers and 111 uncontrollable withdrawal points to distribution networks.[77]

Although injections are normally scheduled uniformly for the balance of the gas day, on days of high demand, linepack can be boosted at the start of the day by injecting at higher flows during the early part of the day and at lower flows later in the day. These arrangements require the consent of affected parties at the injection point. By increasing flow early in the day, the linepack is higher at critical times such as the evening peak, as demonstrated in Figure 6.4.

77 Controllable injection and withdrawal points flow gas according to a schedule. Uncontrollable withdrawal points, such as distribution networks, are not scheduled and do not respond to the market price.

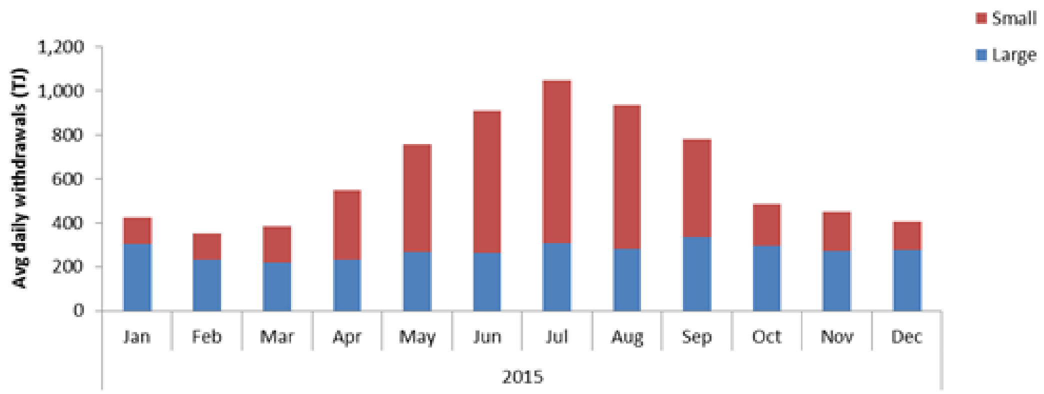
Figure 6.4 Stylised example of profiled injections



AEMC analysis.

Large connections, including interconnection points and gas-fired generation, show limited seasonal variation. Small connections, such as residential customers, show more extreme seasonality and comprise 70 per cent of total withdrawals in winter versus only 30 per cent in summer, as can be seen in Figure 6.5. During winter in 2015, maximum demand on the system was 420 percent of minimum demand.

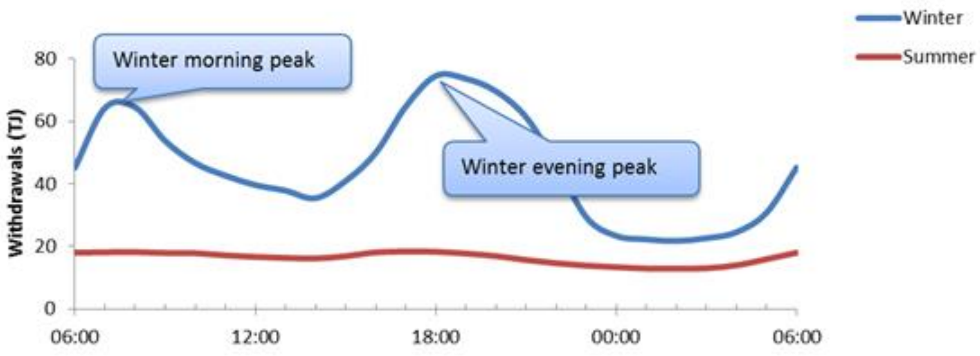
Figure 6.5 Average DWGM withdrawals by size - 2015



AEMC analysis based on AEMO publically available data.

Figure 6.6 shows the typical winter intraday withdrawal profile, which shows morning and evening peaks in demand, and the summer withdrawal profile. Injections are typically scheduled uniformly for the balance of the gas day, so the variable withdrawal profile changes the quantity of gas stored in the pipeline (the linepack). While withdrawals exceed injections, the linepack will decrease (and vice versa). The linepack therefore plays a critical role in maintaining system security in the DTS during winter and highlights the need to manage it efficiently.

Figure 6.6 DWGM typical intraday profile



AEMC analysis based on AEMO publically available data.

Linepack management

Linepack is calculated for individual pipeline segments and the system as a whole. Both segment and system linepack are relevant, because while the system may have total linepack above the minimum level, a pipe segment may have linepack below minimum levels. Where linepack in a pipeline segment is below minimum, but the system linepack is still above the minimum, action may be taken to re-distribute the linepack between pipeline segments by running compressors.

The management of linepack is important to ensure that system pressures are within upper and lower limits. As noted above, injections are generally uniform for the balance of the day, but demand varies significantly. This means that when demand is greater than the rate of injection, the demand is being fed from linepack – which decreases linepack and system pressures.

The timing of injections and withdrawals is also important. If linepack is lower than the target early in the day, the higher the risk that action will need to be taken later in the day that is both larger in scale and longer in duration then may otherwise have been the case if linepack was managed appropriately.

If the pressures reach the minimum allowable pressure anywhere, action must be taken to maintain minimum pressures – by either increasing injections or decreasing withdrawals (or both). The opposite applies when demand is less than the rate of injection, when curtailing consumption may be necessary in an emergency.

Curtailments can be required because increasing injections is not always an option. As gas is a physical substance with mass, increasing injections will only increase pressures once the increased flow has physically arrived. This means that – depending on location of the low pressure – only certain injection sources can be used to increase injections (as discussed in Box 6.2).

Box 6.2 Role of Dandenong LNG storage

The DTS has an LNG storage tank connected at Dandenong on the Longford to Melbourne pipeline. This is on the outskirts of the main Melbourne demand zone and is capable of starting injections of vaporised LNG in around one hour. The Dandenong LNG storage facility is often the only injection source capable of relieving low pressures in the Melbourne area within required time frames.

Unlike other system injection points, AEMO directly notifies the LNG storage facility operator when injections are needed. The facility operator then manages scheduled injections to meet the required flows. System withdrawals to manufacture LNG are included in market participant demand forecasts.

Information availability

The DWGM provides a Market Information Bulletin Board (MIBB) that gives open access to public information and restricted access to a market participant's confidential information. The availability and timeliness of information provision are a key aspect when considering a balancing regime for the Southern Hub. An overview of the information provided by AEMO is set out below.

System information

AEMO publishes public system information on an *hourly* basis, including:

- net injections and withdrawals at controllable system points (ie those that at which market participants may bid);
- net withdrawals by distribution networks;
- critical system pressures; and
- system and system point constraints.

Market participants can correlate this information with historical consumption, current customer profiles and weather observations to calculate their demand forecast for upcoming gas days, and to update their demand forecast for the current gas day.

Schedule information

AEMO publishes information with each of the five daily schedules - 6am, 10am, 2pm, 6pm and 10pm. Public information includes scheduled hourly controllable injections and withdrawals (aggregated by system point), aggregated market participant hourly demand forecasts, AEMO's independent demand forecast and details of any demand forecast override.

AEMO publishes information with each of the five daily schedules - 6am, 10am, 2pm, 6pm and 10pm. Public information includes scheduled hourly controllable injections and withdrawals (aggregated by system point), aggregated market participant hourly

demand forecasts, AEMO's independent demand forecast and details of any demand forecast override.

Market participant information

Market participants first receive confidential metering data via the MIBB three business days after the gas day (D+3), and continue to receive updated data until the revision settlement is issued by 123 business days after the end of the month in which the gas day occurred. A full set of meter data is always published, but where actual data is not available, consumption is *estimated*.

The data quality improves over the 123 day period, as only actual data for the larger interval metered customer sites is reliably available at D+3. The data is published on D+3 to allow for allocation and sub-allocation of meter data at controllable injection and withdrawal system points to take place within the three day window.

Market Participants also receive aggregated metering data in prudential monitoring and settlement MIBB reports that are published between D+3 and the issue of revision settlement statements. Market Participants who are retailers receive meter data for accumulation meters the day after they are read via the retail market systems. This data is primarily used for retail market billing.

Peak demand system information

AEMO issues system wide notices alerting participants to system conditions on peak demand days. These notices are provide information on:

- intra-day demand/supply shortfall likelihood;
- low linepack conditions and LNG scheduled;
- changing weather conditions (effective degree day increases); and
- ad hoc schedule issued to maintain system security (threat to system security).

6.3.2 Option 1: Continuous market-based balancing

Option 1 provides for a continuous market-based balancing mechanism that allows shippers to determine when and how to take balancing actions, minimising overall system balancing costs. AEMO would act as the residual balancer and the party ultimately responsible for system security. An example of how this approach could work at the Southern Hub is outlined in Box 6.3.

Box 6.3 Continuous market-based balancing at the Southern Hub

A small retailer has injected 5 TJ of contracted gas and 2 TJ of gas purchased on the exchange and expects its customers to withdraw 7 TJ throughout the day. As the evening peak approaches, the retailer is receiving information from AEMO that its distribution network connected customers are expected to withdraw 8 TJ due to Victorian weather being colder than expected.

As the total system balance published by AEMO is within the dark green zone and expected to stay that way through the evening peak, the small retailer elects to take no action and is 'short' gas throughout the day. The retailer is effectively borrowing linepack to meet its short position and is charged a nominal fee for doing so.

The next day the retailer still has a short position with AEMO, but the weather in Victoria is warmer and an LNG train in Queensland has tripped unexpectedly. This has resulted in a low gas price at the Southern Hub and the small retailer purchases an additional 1 TJ balance-of-day product over its requirements for the next day so that it now has a 'balanced' position with AEMO.

Potential benefits

This approach maximises the system's linepack flexibility on any given day, potentially reducing costs for shippers. Shippers who are out of balance while the total system linepack is within the 'dark green zone' would not need to immediately procure balancing gas, potentially better utilising linepack flexibility than currently occurs in the DWGM.[78]

Such an approach could lower barriers to entry for small retailers and large industrial customers, as they would have greater certainty over the magnitude of imbalance payments on a daily basis (if any are in fact incurred). Shippers would have an understanding throughout the day as to their portfolio position and the total system imbalance, and would trade-off the costs of purchasing balancing gas against not acting, or having their imbalance settled by AEMO.

Further, as the system was moving out of balance, participants would see this happening and could utilise their physical gas positions as well as trading on the exchange to restore any portfolio imbalances. This makes shippers collectively responsible for resolving their own system imbalances and minimises the role of the system operator. We understand that this mechanism is effective, with Gasunie only required to take balancing actions in 100 out of 8,760 hours a year, on average.

Minimising the role of the system operator is important because shippers have a strong profit incentive to minimise their own balancing costs, which extends to minimising

78 As discussed above, Gasunie requires damping to maximise available linepack by profiling injections supplying uncontrollable withdrawals. We note that this may be a useful concept to consider further, provided injection points to the DTS can be profiled.

total system costs. AEMO's role would be focussed on undertaking residual balancing tasks through taking action to protect system security if shippers' collective actions were inadequate to support system security.

As AEMO would operate the DTS and the exchange, it would lead the development of spot market products to meet the needs of participants and the system. Daily products, daily locational products as well as hourly products (such as Dandenong LNG) could be introduced based on the same trading system operating at Wallumbilla - establishing one form of gas trading for shippers on the east coast.

While the DTS linepack is required to be managed carefully, the Commission understands that the Dutch transmission system has similar operational constraints and that this form of balancing regime has been operating successfully since April 2011. Our preliminary view is therefore that there does not appear to be any unique attributes of the DTS that would prevent continuous balancing being implemented at the Southern Hub.

Potential costs

The Commission has identified the following potential high-level costs of implementing Option 1 relative to the current DWGM:

- AEMO developing new processes, market systems, market interfaces, and training operational staff.
- APA Group and other participants potentially upgrading some meter infrastructure.
- Market participants developing new internal balancing processes, market interfaces and training staff.

The Commission understands that components of the DWGM system are approaching end of life cycle, and AEMO will soon be commencing an upgrade process. Depending on the extent of the system upgrade and the new system requirements, this may result in low additional costs incurred compared to what otherwise would have been the case. With AEMO's DWGM system fully depreciated, this presents an opportune time to implement a new balancing system that is fit-for-purpose into the future.

Due to the level of sophistication in the provision of information under the Dutch system, the adequacy of the existing metering infrastructure will need to be determined and upgraded if required. The Commission notes that while AEMO already receives some hourly information, further work would need to be undertaken to assess the adequacy of this and the ability to develop mathematical techniques for estimating allocations on an hourly basis (or similar). The Commission is interested in market participants' views on this issue.

Market participants will need to develop new processes for interacting with the market and managing their imbalances, and there will be internal resourcing costs incurred to achieve this.

6.3.3 Option 2: Fixed period market-based balancing

A fixed balancing period, such as 24 hours, would require that shippers' portfolios are balanced at the end of this period. This means that shippers out of balance during the period would have until the end of the balancing period to take action or have the imbalance settled by AEMO at market-based prices. Similar to Option 1, AEMO would be the residual balancer and responsible for system security.

Box 6.4 sets out an example of how this could work at the Southern Hub.

Box 6.4 Fixed balancing period at the Southern Hub

A fixed balancing period is implemented over 24 hours from 6am, inline with the gas day start time. During this period Shipper A intends to inject 80 TJ and purchase 20 TJ on the trading market, for total injections of 100 TJ and total withdrawals of 100 TJ.

By 2pm during the gas day Shipper A's internal systems indicate that withdrawals have likely already reached 100 TJ due to higher than expected residential demand and demand from its gas-fired generation customers. At this point Shipper A's withdrawals over the remainder of the gas day are expected to exceed its injections.

Shipper A has until 6am to take action to rectify this imbalance or be settled at market-based prices by AEMO. Shipper A chooses to purchase a combination of balance-of-day products on the exchange and OTC such that its injections across the gas day equal withdrawals, with zero imbalances to be settled by AEMO at the end of the day.

Potential benefits

A fixed balancing period encourages participants to trade within the day to balance their portfolios by the end of the day. They can do this by using the information available to estimate their portfolio position and by monitoring the total system pressure. If shippers are long or short gas, they are able to rectify this by calling on contracted gas, storage and trading on the Southern Hub exchange or OTC (or any other potential means).

As shippers are not required to balance their portfolios at more regular intervals, the flexibility of a 24 hour balancing window allows gas to be purchased at least cost over the day. The trade-off shippers are required to make is whether to take action to rectify any imbalance (and when) or be settled by AEMO at the end of the day. By monitoring system pressures and the prices of exchange-trade products, shippers can determine the actions which will most likely minimise their balancing costs.

However, we recognise that the operational characteristics of the DTS may require AEMO to take actions within the balancing window to maintain linepack adequacy and protect system security. This is likely to occur more often under a fixed 24 hour period as shippers are not required to balance their portfolios within the period, irrespective of the overall system balance.

Put another way, if a shipper is out of balance during the balancing window and system pressures are dropping below operational limits, the shipper is not required to take action to balance its portfolio until the end of the period. Instead, AEMO would need to take action to restore linepack pressures to within operational limits and allocate the costs of doing so across all market participants.

Consistent with a market-based balancing regime, it may be appropriate to impose some of these costs on shippers who cause them (cost-to-cause principle), although this reduces the benefit of a 24 hour fixed balancing period. Consultation on any intraday mechanism would need to occur to prevent obligations on shippers that result in a barrier to entry.

A benefit of the fixed period approach is that it may not require the same amount of change to metering infrastructure and systems that a continuous approach would. The information provision capability of the DWGM, where the market is balanced multiple times per day, may be sufficient to implement a 24 hour balancing window. Although, work would need to be undertaken on the quality of information shippers receive to allow them to take informed balancing actions during the day, if they choose.

Potential costs

As discussed above, under a fixed balancing period AEMO will more likely need to take action during the day to protect system security. This is because shippers are not required to balance their portfolios until the end of the period and may have an imbalance throughout the day that contributes to a system security issue.

Further, as shippers are allowed to be out of balance during the period, most of the costs incurred by AEMO would likely need to be allocated across all shippers so that the benefits of a fixed balancing period are not undermined. The physical characteristics of the DTS could result in these costs being large on some days.

In terms of direct costs of implementing this approach, these are likely to fall into the same categories as those set out for the continuous balancing model. However, we note that as a fixed 24 hour period is less sophisticated than continuous balancing, system and set up costs may be less.

6.4 High level assessment and proposed approach

Both models are assessed positively against all principles set out in section 6.1. Each has a residual balancer role that would be undertaken by AEMO to support system security. The models support market-based balancing as shippers have an incentive and the required information to balance their own portfolios efficiently, potentially resulting in less action being taken by AEMO on shippers' behalf.

Each model supports transparent and non-discriminatory balancing using exchange-based trading. In this way, the market values the flexibility inherent in balancing gas throughout the day in response to the short term supply and demand. Shippers can also trade-off using their own resources, such as flexibility in production nominations and/or storage, against purchasing exchange-based products to restore any imbalance. Or they may wish to be settled at the end of the gas day by AEMO and incur the costs AEMO faced to take balancing actions.

Fixed period market-based balancing did not score as high on cost-to-cause incentives. As discussed above, this reflects the greater likelihood that AEMO would be required to take unilateral actions throughout the day to balance the system and the costs of these would generally be spread across all market participants. Each scheme is assessed as being simple, but effective once implemented.

Irrespective of the balancing model, the Commission is currently of the view that a separate balancing platform at the start of the Southern Hub is not the preferred approach and that shippers should utilise the Southern Hub exchange to trade spot products for balancing. This approach would concentrate all trading for spot products at a single point, contributing to the development of liquidity. As discussed in section 6.1.4, a separate balancing platform splits trading of spot products, as gas cannot be offered for balancing and on the exchange at the same time.[79]

The Commission notes that this high-level assessment does not take into account costs associated with moving the DWGM to either balancing model, which are likely to be different for each approach and are highlighted in 6.3.2 and 6.3.3. This assessment focuses on the potential effectiveness of each model once implemented.

6.4.1 Proposed approach to balancing at the Southern Hub

While there is further work to be done to assess each model in more detail, the Commission is attracted to continuous balancing as it maximises the use of the system linepack on any given day. It also provides the tools for shippers to manage their own portfolio positions, while designating AEMO as the residual balancer responsible for system security.

Further, the Commission is aware that a fixed 24 hour balancing window may result in AEMO having to undertake substantial within-day balancing actions to manage the DTS. This is because shippers do not have to balance their portfolios throughout the day and this could potentially result in AEMO having to take costly actions to manage linepack, with the resultant charges spread across all participants. Consequently, a 24

79 We note that while some shippers may be nervous about the level of liquidity present at market start, an extended trial period could provide participants with an opportunity to become familiar with trading spot products to manage their imbalances.

hour window is likely to provide less efficient balancing outcomes than under a continuous approach.

To a large extent, the cost/benefit equation of implementing a continuous market-based balancing regime will depend on potential costs associated with upgrading meters and systems to provide AEMO and shippers with more regular and detailed information than currently exists. The magnitude of these costs will not be able to be quantified until further technical work is carried out.

As discussed in section 6.1.3, incentives to remain in balance are an important factor in the design of a balancing regime. Shippers who have an imbalance could face the average cost or marginal cost of AEMO's actions to balance the system. The approach chosen can have implications for competition and the incentives on shippers to supply and purchase spot gas on the exchange. This issue was not considered in detail in this paper, which focussed on the overall balancing regime.

Given this, the Commission's proposed approach is to continue to quantify the costs and benefits of the continuous market-based balancing model leading up to the Final Report for the Review of the DWGM, with technical input from industry and AEMO. We will also be doing further work to understand the different implications of applying an average cost or marginal cost balancing incentive on shippers.

The Commission's intention is to provide a recommendation to the Energy Council on the most appropriate a balancing regime for the Southern Hub in the final report.

Box 6.5 Stakeholder questions

The Commission welcomes stakeholder views on any of the issues raised in this chapter. In particular, we are interested in the following points:

- Whether a continuous balancing period, similar to the Dutch system, could be implemented at the Southern Hub. Consideration should be given to the costs and likely benefits of this approach.
- Whether the procurement of balancing gas could occur through the purchase of spot products on the Southern Hub exchange at market start, or whether a separate balancing platform is required.
- In the instance a fixed balancing period was considered appropriate, what an appropriate timeframe would be.
- Stakeholders views on the role of AEMO as residual balancer and how it should perform this function.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	authorised maximum daily quantity
AMDQ cc	AMDQ credit certificates
APA	APA GasNet
COAG	Council of Australian Governments
Commission	See AEMC
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
FCFS	first-come-first-served
Gasunie	See GTS
GTS	Gasunie Transport Services B.V.
GWCF	Gas Wholesale Consultative Forum
LNG	liquefied natural gas
MCE	Ministerial Council for Energy
MIBB	Market Information Bulletin Board
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NTS	national transmission system
OBB	over-subscription and buy back
OCM	On The Day Commodity Market

OTC	over-the-counter
SBS	System Balancing Signal