11 May 2017

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Mr John Pierce
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Australian Energy Market Commission
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Dear Mr Pierce

Australian Energy Market Commission Victorian Declared Wholesale Gas Market Assessment of Alternative Market Designs (GPR0002)

AEMO welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC) Declared Wholesale Gas Market (DWGM) assessment of alternative designs.

AEMO recognises the additional work undertaken by the AEMC to develop a broad suite of market reform options in addition to the Southern Hub model developed in 2016.

We agree that the DWGM design needs to adapt to the rapid and ongoing changes being experienced in the east coast gas industry and in the National Electricity Market. We consider that incremental reform options to enhance the market's design should be pursued so that the benefits of change can be delivered in a timely manner. We note that the options proposed (in particular those that would represent a substantial change to the market framework) will require further design and assessment work prior to implementation.

This submission is provided in two sections:

- **Attachment A – Proposed market reforms:** builds on several of the design options presented in the AEMC's report to develop a proposed package of market reforms for the DWGM
- **Attachment B – Assessment of design options:** provides our view on the potential benefits and risks of the options presented in the report

AEMO looks forward to engaging further with you as you prepare the Final Report for this review. If you would like to discuss the contents of this submission further, please do not hesitate to contact Violette Mouchaileh on 03 9609 8551.

Yours sincerely,

Peter Geers

Executive General Manager, Markets

cc:

Attachments: Proposed market reforms, Assessment of design options

Attachment A – Proposed market reforms

1 Introduction

On 30 March 2017, the AEMC released a paper providing alternative market designs for the Declared Wholesale Gas Market (DWGM). The Paper described a broad range of design options that can be grouped into three categories:

1. **Spot Market -** options to address pricing, scheduling and trading in the DWGM
2. **Forward Market -** options to develop a forward or financial market in Victoria
3. **Capacity Rights -** options to change transportation rights to improve investment signals.

Leveraging the options outlined in the AEMC's *Alternative design options* paper, AEMO has constructed a package of options that we consider largely addresses concerns from stakeholders around existing limitations of the DWGM and will promote the National Gas Objective (NGO). Specifically, our package incorporates the AEMC options: 3.2 (simplified uplift), 4.3 (forward market integrated with the DWGM), 5.2 (secondary trading of AMDQ) and 5.3 (exit AMDQ). We have made some modifications to the AEMC's options as described and have added some additional design elements to ensure that the package is robust and comprehensive. In summary we recommend the following:

Spot Market Recommendations

1. Improve trading and liquidity in the spot market by simplifying the uplift framework through removing congestion uplift (modified option 3.2).
2. Improve spot market price signals through introducing a flow constrained pricing mechanism, which will provide locational price when a facility is constrained and allow for additional trading.
3. Improve information transparency through enhancing the accessibility and presentation of DWGM information.

Capacity Rights Recommendations

4. Implement a new planning standard for the Victorian Declared Transmission System (DTS) to guide investment in infrastructure and support the efficient creation and allocation of AMDQ.
5. Improve capacity rights by redefining existing AMDQ to entry AMDQ and introducing withdrawal AMDQ (or exit AMDQ) to better manage withdrawal scheduling risk (option 5.3).
6. Introduce portfolio rights trading to enable secondary trading of AMDQ (option 5.2).

Forward Market Recommendation

7. Introduce a physical forward market by listing Victorian gas products on the Gas Supply Hub and integrate delivery with the DWGM to support the management of gas price risk and inter-hub gas trading (option 4.3).

AEMO considers that implementation of these recommendations, consistent with the COAG Energy Council's vision and Victorian Government's terms of reference. The implementation of the recommendations would improve risk management and the efficient pricing and allocation of gas in the DWGM and between the facilitated gas markets, supporting growth in trading liquidity. Regarding the implementation of these options, we consider that a physical forward market could potentially be implemented independently and in advance of the recommendations for capacity rights and the spot market which will require more substantial design work and longer implementation timeframes.

2 Spot market recommendations

AEMO considers that the DWGM's spot market generally functions well with the gross pool providing industry with a liquid trading market that reduces barriers to entry, particularly for smaller participants.

However, we believe that the spot market could be improved through some targeted changes to better meet the needs of industry into the future.

2.1 Simplifying the allocation of uplift

Uplift is the mechanism by which the costs of funding ancillary payments (AP) for out of merit order gas are allocated to market participants. The current uplift allocation model was largely designed for a constrained point-to-point network (which has since been expanded), where a temporal constraint and a change to conditions (a surprise event) results in the need for Dandenong LNG to be scheduled. Or a scenario where congestion (large volume of withdrawals relative to supply and transportation capacity) requires LNG to be scheduled to maintain minimum pressures. The intention of these arrangements was to allocate any costs to the causers of the event within the confines of virtual hub, with a single price and fixed scheduling and pricing periods.

As articulated in the AEMC's paper and identified in a number of industry submissions to this Review, the methodology for the allocation of uplift payments is complex and may not always achieve cost to cause. It has been posited that the uncertainty and potential risk associated with uplift costs may be inhibiting participation in the spot market and trading in the ASX's DWGM futures product.
AEMO considers that the best way to address these concerns would be to simplify the uplift allocation methodology (similar to the AEMC's option 3.2). Much of the complexity of uplift is associated with the desire to achieve cost-to-cause and so it can be reasonably assumed that a simplification of uplift will likely result in a greater degree of smearing of uplift costs.

Greater socialisation of uplift costs may be seen as a desirable trade off if it results in a simpler market design in which risk is easier to manage, trading volumes are greater and prices are therefore more informative for consumers. In addition, cost-to-cause for poor forecasting and schedule non-conformance could be maintained through retaining surprise uplift. As outlined in *Attachment B* of our submission, we are not supportive of options 3.1 or 3.3 as we believe these would negatively impact market trading volumes and liquidity due to the punitive nature of the mechanisms, particularly on participants without flexible portfolio options.

Congestion uplift background
Congestion uplift is charged to participants who exceed their Authorised Maximum Interval Quantity (AMIQ). At a high level, the AMIQ profile is the participant's AMDQ profiled over the gas day subject to certain maximum limits. In order for an AMIQ profile to be valid for the purpose of a hedge against congestion uplift it must have a corresponding injection hedge nomination. The rationale is that those participants whose consumption exceeds their AMIQ are in effect consuming more gas than authorised (as per their AMDQ property right) and are therefore contributing to the congestion of the system.

To hedge against congestion, uplift a participant must:

- At the 6am schedule forecast to consume less gas than its nominated AMIQ for each scheduling interval and,
- For intraday schedules not increase their forecast or withdrawals relative to their AMIQ profile.
- Nominate an injection hedge and be scheduled to inject to support their AMIQ profile
    - Alternatively, the participant can have an agency injection hedge nomination in place with another participant who injects on their behalf.

Issues with congestion uplift
A number of issues have been identified with hedge-ability of congestion uplift and that the need to manage congestion uplift adds to much of the market's complexity. Because of these issues, which we outline below, we consider that congestion uplift may be contributing to inefficient market outcomes and therefore its allocation should be reviewed. The remainder of this section provide an analysis of the issues associated with congestion uplift.

Firstly, the congestion uplift hedging mechanism is complex with a participant having to profile its AMDQ across the gas day and then nominate a portion of their injections to cover that AMIQ position.

Because of the risk associated with congestion uplift, and the complexity in managing exposure there may be an incentive for participants to have inefficiently large injection hedge nominations which they do not modify.

Secondly, the ability to hedge congestion uplift is restricted to participants with physical injections matched to the location of their AMDQ and this may negatively impact trading. This means that a participant that is simply a buyer from the spot market is unable to directly hedge against congestion uplift even if it has AMDQ. Its only option is to enter into an agency injection hedge nomination (AIHN) with an injecting participant at the location of its AMDQ and this injecting participant may be a competitor and unwilling to provide the buyer with an AIHN. It also increases the transaction costs of purchasing gas from the spot market as this arrangement needs to be entered into bilaterally and ex ante.

The other option left to a participant is to acquire its own supply contract. This may be challenging if the participant only requires a small volume (which is likely for a spot market buyer, particularly a new entrant) as well as ultimately reducing the traded volume in the market. The need to have injections to support an AMIQ profile may serve as a disincentive to buy volumes through the spot market (or through forward trading) due to the inability to effectively hedge against congestion uplift. Ultimately, the requirement for an uplift hedge to be supported by an injection encourages participants to take a physical injection position and not optimise through trading their commercial position where it is efficient to do so.

Thirdly, a participant who exclusively wheels gas from Longford to Culcairn through the DTS is unable to hedge its congestion uplift exposure. Although the participant is injecting at Longford it requires AMDQ in order to have an AMIQ profile and it cannot acquire AMDQ without acquiring tariff V or tariff D customers in Victoria - which it is unlikely to have if its simply transporting gas through the system[1]. Consequently, the inability to hedge congestion uplift for a participant wheeling gas through Victoria may serve as a disincentive to inter-regional trade (which is one of the objectives of this reform process).

Is the type of congestion originally envisioned by congestion uplift an issue in the DTS?
On a very high demand day, it is possible to have a situation where demand is so high that injections scheduled in the pricing schedule from the major supply sources exceed the capacity of the pipelines connecting those supply sources to the demand centre, requiring more expensive gas (typically LNG) to be scheduled elsewhere in the operating schedule to meet demand. It is important to note that a congestion event can occur even if every participant perfectly forecasts its demand and injects in accordance with its schedule quantity – this is what distinguishes a congestion event from a surprise event and is a characteristic of a virtual hub. Congestion uplift was intended to fund the ancillary payments required to address such events and create the incentive to invest in capacity to relieve congestion.

The type of congestion outlined above is currently less likely to occur than in the past in Victoria given physical and commercial changes in the market and this brings into question the appropriateness of the congestion uplift framework. The contributors to a reducing probability of this type of congestion include the expansions to the capacity of the southwest pipeline, forecast decreases in production, coupled with demand that is forecast to continue decrease over the next five years. What is more likely in the near term is locational congestion due to transportation constraints (including constraints related to maintenance and outages). However, congestion uplift is a market-wide allocation and is unlikely to achieve a cost-to-cause allocation of uplift for locational congestion issues.

This dynamic was evidenced by the recent event on 1 October 2016 where an adhoc schedule was required to schedule out of merit order gas to address a system security issue caused by an unplanned outage at Longford Gas Plant. A large portion of the uplift charges created by the event were allocated to congestion uplift despite the event not being related to congestion.

[1] Alternatively the participant could invest in additional capacity to acquire AMDQ CC. However, this would not be an efficient outcome given there is unutilised capacity that they cannot acquire a right for.

As described, under the current methodology, congestion uplift may be allocated regardless of what triggered the ancillary event - it simply requires a participant to exceed its AMIQ or an intraday change in its AMIQ exceedance. Given the infrequency of system demand driven congestion the inefficient allocation of uplift costs to congestion uplift for most ancillary events is likely. Without the introduction of a form of locational pricing, which would increase the market's complexity and potentially negatively impact liquidity, it may be more efficient and equitable to socialise these costs especially if they are infrequently incurred and only for a small amount.

Given the lower likelihood of system demand driven congestion, the current ineffective allocation approach, and considering the Energy Council's focus on trading liquidity and efficient pricing, the NGO is likely to be better promoted by removing congestion uplift and socialising these costs. The introduction of a formal planning standard, as discussed in section 3.1, will also act as a mechanism to manage future levels of congestion on the DTS and therefore mitigate against any unintended outcomes. High forecast levels of congestion could also be a trigger to consider firmer transportation rights and after the implementation of a planning standard, the AEMC could consider this as part of their biennial liquidity review.

Removing congestion uplift and its market implications
Given the issues associated with congestion uplift it may beneficial to remove it from the uplift allocation methodology. Such a solution is likely to better promote the NGO if it can be established that:

- System demand driven congestion in the DTS is rare and therefore the removal of congestion uplift is unlikely to materially impact incentives for investment, especially where congestion uplift costs when averaged over a year are likely to be low.
- The ability to allocate the costs of congestion to the actual causers is sufficiently difficult that misallocation is likely meaning that socialising the congestion costs is appropriate.
- The introduction of a new formal planning standard will effectively manage future levels of congestion to protect against un-intended outcomes.

If congestion uplift is removed, injection hedge and AMIQ nominations would no longer be required to hedge against uplift. This would remove one of the complexities of the market's design, as identified by the AEMC but also potentially devalue AMDQ (given its role in hedging against uplift). Under this approach, if genuine system congestion occurs and this requires the scheduling on of out-of-merit order gas, assuming there is no surprise uplift, the costs would be recovered from common uplift (currently socialised across withdrawals). That is to say, when genuine congestion on the system occurs it is socialised across the system's users regardless of whether they hold AMDQ.

The AEMC have made references that AMDQ is not sufficiently firm to impact investment decisions which are made through a regulatory approach. Therefore, removing congestion uplift is unlikely to negatively impact investment decisions[2]. Under this approach, AMDQ will be primarily be for the purpose of tie-breaking and providing limited curtailment protection in the event of a transmission constraint. We also note that the impact on AMDQ would be the same under the implementation of constrained pricing option (option 3.1), where AMDQ would not provide a hedge against the constrained price.

In addition, the removal of IHNs may increase the amount of ancillary payments. Injections that are scheduled on but are used for a congestion uplift hedge are not eligible to receive ancillary payments (as this would be double dipping). Without IHNs all injections that are scheduled on would be eligible for ancillary payments – potentially increasing the total quantum of ancillary payments depending on bidding strategies.

The core benefit of removing congestion uplift would be to simplify the market's design, and improve risk management for trading participants (particularly new entrants) and encourage greater trading through the spot and forward markets (if a forward market is implemented). We would envisage that this change would see an increase in trading activity and liquidity as a consequence. In addition, as

[2] AEMC, Assessment of Alternative Market Design, p. 28, 30 March 2017

uplift risk would now primarily be related to surprise uplift, it may be possible to create more targeted products to hedge against surprise uplift (such as a cap product linked to LNG).

Implications for investment if congestion uplift is removed

The AEMC have suggested in the Alternate Design Options Paper that the relationship between AMDQ as a congestion uplift hedge and investment is not strong as most investment is made through a regulatory approach. Under our proposal, the role of AMDQ in the market would be to serve as a tie-breaking right and to provide limited curtailment protection in the event of a transportation constraint, the role of AMDQ in hedging against congestion uplift would no longer exist.

As AMDQ does not provide a strong signal for investment to relieve congestion, and this signal would be further diminished by the removal of congestion uplift, a review of the regulatory investment framework and in particular whether a planning standard in Victoria should be introduced is warranted. The planning standard should be designed to ensure that system has sufficient capacity to meet a certain level of demand and that there is an efficient level of congestion. This standard should guide any future investment (and creation of new AMDQ) in the regulated asset base that is required to meet the planning standard. The planning standard should provide greater clarity to the current regulatory investment framework and benefit consumers by ensuring that congestion is managed at an efficient level. We discuss the introduction of a statutory planning standard and the regulatory investment framework further in section 3.1

Surprise Uplift should be retained

In our assessment, we consider that the surprise uplift component of the uplift allocation methodology should be retained. Participants are potentially liable for surprise uplift when they change their demand forecast or deviate from their scheduled withdrawals or injections. This uplift exposure creates the incentive for participants to forecast accurately which is important for ensuring allocative efficient market outcomes. Further, surprise uplift ensures an appropriate allocation of surprise event costs between participants and in particular between those with flat and variable demand profiles.

For example, if poor forecasting of retail load on a cold day leads to the need for ancillary payments it is appropriate that these ancillary payments are funded by those whose poor forecasts caused the need for out of merit order gas (as would happen with surprise uplift). Without surprise uplift, the cost of such an event would be paid for by all consumers including those with flat loads who forecast accurately and withdraw and/or inject in accordance with that forecast and so do not contribute to the event.

By removing an incentive to forecast accurately through smearing the costs of poor forecasting, forecast errors may be larger and in turn this may lead to larger ancillary payment events the costs of which will be paid for by consumers. If the AEMC decides to remove surprise uplift as per option 3.2, then the forecasting framework could be re-examined including the demand override methodology and whether the market is scheduled to AEMO or participant's forecasts.

2.2 Directional flow point constraint pricing

A further improvement to the spot market would be in the introduction of directional flow point constraint pricing (DFPC) to enable additional trades through a locational price when a pipeline or facility is flow direction constrained. When a flow direction constraint binds on a paired system withdrawal and system injection point, a scenario can occur where additional injections and withdrawals at the point can be scheduled above the market schedule. The market would schedule the additional economic withdrawals and injections and a direction flow point constraint price would be used to settle these additional trades. Importantly, the additional quantity of withdrawals and injections would be equal and so the net flow at the paired injection/withdrawal meters would remain unchanged. The injector who injects above the market price would be compensated by the withdrawer.

This mechanism cannot be facilitated under the current settlement arrangements as the constrained on injector would not necessarily be compensated by the corresponding withdrawer (due to uplift's allocation methodology), and as such changes to the settlement and scheduling systems would be required to facilitate DFPC pricing mechanism.

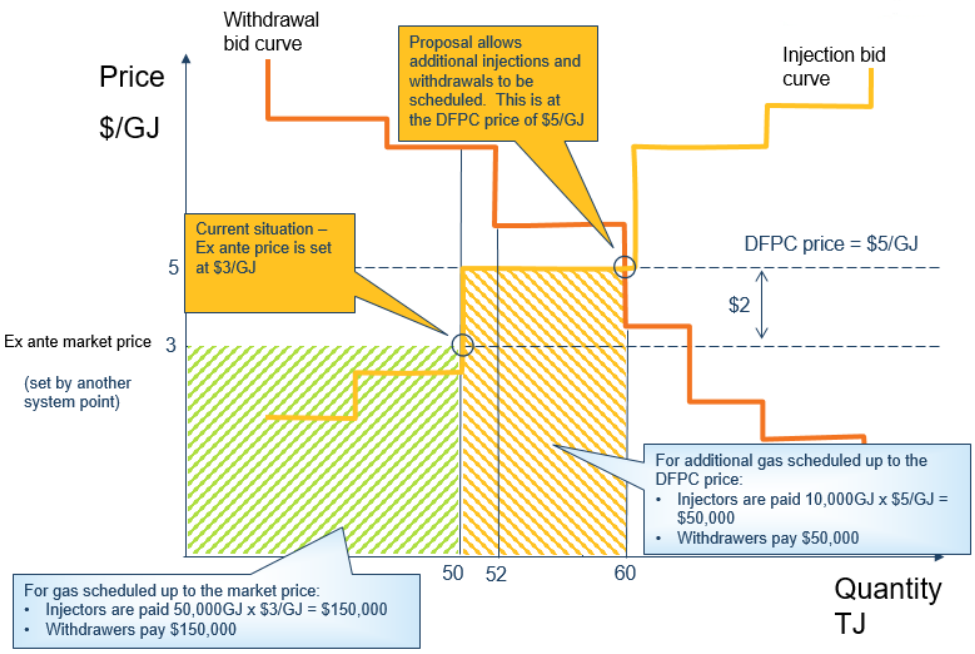
Design issues to resolve would include whether all participants at the constrained point pay the DFPC price (as in the STTM) or just participants scheduled above the market, and whether the DFPC price is a clearing price or is pay as bid. The interaction between the prices and intra-day reschedules would also need to be considered as this is a notable difference from the STTM. AEMO would need to undertake further scoping for the current market scheduling and settlement systems to determine the best way of facilitating this pricing mechanism[3].

The benefit of this mechanism is that it enables additional trade at a location where there is a transportation constraint and buyers at that location value gas at a price above the common price in the virtual hub. This could be particularly valuable where a participant is trying to withdraw additional gas into storage, or looking to trade gas inter-regionally. It also is considered a more proportionate response than implementing full zonal or nodal pricing to achieve locational price signals.

It should be noted that this pricing mechanism was also consulted on briefly by AEMO through the Gas Wholesale Consultative Forum (GWCF), in 2014. At the time, the benefits were not deemed to be worthwhile to pursue implementation of this mechanism. However, with further changes to system flows (greater levels of controllable withdrawals) and the changes to DWGM IT systems that would be required if other review recommendations are implemented, it would be worthwhile to revisit this concept.

Below is a worked example of the DFPC pricing Mechanism at a system withdrawal point with a bi-directional meter than cannot physically withdraw from the system (for example the VicHub SWP/SIP).

Figure 1: DFPC Pricing Mechanism



If an DFPC of net withdrawal = 0 is applied, then it is possible that an injection bid with a bid price > market price is scheduled to maximise the withdrawals at the bi-directional system point. Hence, DFPC price would be higher than the market price under this scenario and is set by an injection bid.

[3] Our preliminary view is that this mechanism could only be facilitated in the pricing schedule.

2.3 Information transparency

AEMO considers that as part of implementing these reforms a review of the DWGM information framework would be beneficial. A large volume of information is published to the market information bulletin board (MIBB) in a CSV file format. The presentation of this information could be improved to make it more readily accessible and interpretable for market participants and could be provided to the Gas Bulletin Board. Improvements could include better presenting linepack information and real-time information and developing graphical displays.

3 Capacity rights and investment in the DTS

AEMO considers that there would be merit in considering options to improve exit rights in the DTS, and, with the removal of congestion uplift and injection hedges, have existing AMDQ operate as entry (or injection) AMDQ for the purpose of tie-breaking. We also consider that the introduction of a statutory planning standard would improve clarity and certainty for network investment that is required to maintain system security.

3.1 Planning standard and the regulatory investment framework

As discussed in section 2.1, the investment and regulatory framework could be more broadly reviewed including the introduction of a statutory planning standard for Victoria determined by the AEMC in consultation with industry and government and managed by the Australian Energy Regulator (AER). The planning standard would be introduced to ensure there is a common view on whether the system has sufficient capacity and whether additional investment is required to meet a specified level of demand. The planning standard would also guide the creation of any new AMDQ.

The AEMC considered the introduction of a planning standard during this review in its first discussion paper in September 2015. The AEMC stated in that paper that “a planning standard would provide an agreed standard against which to assess proposed system augmentation projects for inclusion in APA GasNet’s capital base.” AEMO agrees with this notion and considers that there would be value both for the current market any future southern hub model in establishing a planning standard.

As has been established in this review, the relationship between AMDQ and investment in capacity is weak and could be further weakened by removing congestion uplift (although this is not considered to be material). The introduction of a planning standard would ensure that investment in the system is sufficient to meet a reasonable expectation of forecast demand through the regulatory process.

A statutory planning standard would inform the creation of any new AMDQ resulting from any further investment in the regulated asset base and could aid in the efficient allocation of AMDQ. It should be noted that the capacity at system injection and withdrawal points varies depending on system demand and ideally the planning standard should reflect this so that AMDQ can be created temporally. This could be achieved through applying the planning standard on a seasonal or monthly basis allowing AMDQ (particularly exit AMDQ, see section 3.2) to be created and allocated more dynamically which in turn would support the efficient utilisation of the system enabling participants to better manage scheduling risk.

If congestion becomes a major issue in the future and there’s a desire to have a greater level of market-led investment to address this, then firmer capacity rights should be considered including the options outlined in the alternative design options paper and the entry and exit rights under the Southern Hub Model.

The implementation of a planning standard would be consistent with frameworks in European gas markets. In particular, the introduction of a planning standard could aid the transition to the development of a baseline capacity figure that could be used to determine the auctioned entry and exit capacity in the Southern Hub model.

3.2 Entry and exit AMDQ

Background

AMDQ could be modified to better meet the needs of industry and to support a potential transition to the full Southern Hub model’s entry and exit capacity if this model is endorsed. Under our proposed approach, the role of AMDQ would be changed and this would be similar to the "5.3 withdrawal AMDQ Credit Certificates" proposed by the AEMC in its discussion paper. Without congestion uplift, the role of AMDQ will be primarily to act as a quasi-transportation right through providing participants with greater scheduling certainty through tie-breaking and limited curtailment protection in the event of a transportation constraint for entry AMDQ.

Existing AMDQ is tied to an injection source and the quantity of AMDQ is determined by the agreed capacity between the injection point and the reference hub. This capacity would be determined by the proposed 1:20 year round basis, which means more or less capacity may be available depending on actual demand. This AMDQ (including authorised MDQ for Longford entry) would remain unchanged but would be renamed as entry AMDQ. Its role is to provide a participant with a tie-breaking right at the corresponding close proximity point to provide it with greater certainty that its gas will be scheduled.

It should be noted that Longford AMDQ (authorised MDQ) is owned by customers. For tariff V customers, the rights associated with the AMDQ are allocated to the participant supplying the customer. The ownership framework for authorised MDQ could be reviewed in order to harmonise the arrangements with entry and exit AMDQ Credit Certificates.

Exit/Withdrawal AMDQ

Under the proposed approach, a new category of AMDQ called exit AMDQ would be created. The exit AMDQ would be between the reference hub and a controllable withdrawal point. For example, there would be exit AMDQ between the reference hub and Iona close proximity point (CPP) and separate exit AMDQ between the reference hub and Culcairn.

The quantity of exit AMDQ available would reflect the capacity of the system to flow gas to the controllable system withdrawal point (SWP) and this in turn would be guided by the planning standard. Exit AMDQ is likely to be seasonal as exit capacity is dependent on system demand and so exit AMDQ would likely need to be allocated on a monthly or seasonal basis to maximise the amount that is released.

Exit AMDQ would provide the same tiebreaking rights as entry AMDQ at controllable system withdrawal points. Under the current curtailment procedures, exit AMDQ would not provide curtailment protection as controllable withdrawals will generally be scheduled off (based on bid price) before curtailment of uncontrollable demand.

Exit and Entry AMDQ would need to be distinct rights and the ability to nominate entry AMDQ to an exit point would no longer be possible. For example, the quantity of Longford (entry) AMDQ far exceeds the exit capacity of the southwest pipeline at Iona. If this could simply be transferred over to Iona, it would not provide any meaningful signal especially if this was done on a first come first serve basis. It would also crowd out any market-led investment that results in the creation of new exit AMDQ between the reference hub and Iona. In order to acquire exit AMDQ the participant would have to prove that they have a firm capacity at the SWP. It would be appropriate to put in place a transitional measure for AMDQ that has already been allocated to a SWP and this may need to be related to any contracts that have been entered into to underwrite any interconnected capacity.

Allocation and creation of AMDQ

A further consideration is whether the current AMDQ allocation process needs to be made more flexible. Under the current arrangements, AEMO is only able to allocate AMDQ CC for a five a year period aligned with the access period. This presents an issue where a participant may only want AMDQ for a single year or a single quarter (and is uncertain about its future requirements) but has to subscribe and pay for a full 5 years' worth of AMDQ CC.

It would be more efficient to allow participants to acquire at least some portion of AMDQ CC (which will become entry and exit AMDQ under our proposed approach) on a shorter term basis. The total entry and exit AMDQ available over the access period could be allocated across different tranches. For example, 50 percent of the AMDQ could be allocated via a single auction for the 5-year period with the remaining 50 percent allocated across multiple auctions for yearly, quarterly and monthly tranches. The percentage of AMDQ offered at different time periods could be determined after consultation with industry and prescribed in AEMO's DWGM Procedures so that changes could be made relatively quickly in response with industry needs. This is similar to how entry and exit capacity is auctioned in Europe and would provide participants with greater flexibility in managing their AMDQ position.

The creation of new entry and exit AMDQ could occur in the following way:

- Regulatory creation of AMDQ: where the planning standard results in the expansion of entry or exit capacity in the system this would create new entry or exit AMDQ. This could be allocated via the current AEMO AMDQ CC auction process.
- Market-led creation of AMDQ: if participant underwrites its own investment outside of the regulatory process, and this results in an agreed increased in capacity between the SWP or SIP and the reference, new entry or exit AMDQ would be created. This could be allocated by the DTS Service Provider.

The entry and exit AMDQ has parallels with the entry and exit rights proposed under the AEMC's Southern Hub model. The implementation of entry and exit AMDQ and the planning standard (which would be similar to baseline capacity standard required under the Southern Hub model) would provide a foundation for a future transition of entry AMDQ and exit AMDQ to entry and exit rights.

3.3 Portfolio rights trading/secondary trading

AEMO proposes to supplement the rights model discussed above with a form of portfolio rights trading consistent with the AEMC's proposed option 5.2. This would enable participants to trade the rights associated with entry and exit AMDQ in a secondary market. The trading could be facilitated through a standardised product listed on the Gas Supply Hub Exchange (Trayport) with trades then reflected in the DWGM systems for scheduling purposes.

4 Introducing a forward market in Victoria

AEMO considers the introduction of a forward physical market, similar to the products listed on the GSH at Wallumbilla and Moomba, as a positive step in the DWGM's development. The forward market would provide producers with a platform to sell spare production above long-term contractual commitments ahead of time, while also allowing retailers and large gas users to lock-in a price and quantity ahead of time, aiding their ability to manage risk. Due to the temporal issues associated with transporting gas from a supply source to a demand source gas is typically traded ahead of the gas day. Forward trading gas also opens up the ability for more distant supply sources (for example Moomba or Queensland) to directly supply the market. If the forward market is liquid, the spot market's primary role would transition over time to managing imbalances and deviations.

Gas forward markets also provide an effective mechanism to link the gas and electricity markets. The ability to lock-in gas supply contracts is particularly valuable for gas-fired generators. In combination with the pipeline capacity trading reforms endorsed by the COAG Energy Council, a Victorian forward gas market would facilitate efficient trade and competition between key gas hubs across the east coast market.

We consider a forward market integrated with the DWGM's virtual hub and settlement systems as described in the AEMC's option 4.3, to be the most suitable forward market design for Victoria. The Victorian Forward Product would be traded through the Gas Supply Hub, with forward settlement and prudentials requirements for transactions facilitated through the GSH. Transactions would then be delivered through the DWGM.

As described by the AEMC, under this option, participants procure or sell gas in the forward market. On the gas day the participant's net position in the forward market becomes its delivery or receipt obligation at the 6 AM schedule. The participant then has an obligation to inject or withdraw at the 6AM schedule in accordance with their forward position. If the participant does not get scheduled in accordance with its obligation, then the market would automatically supply (or buy) this unfulfilled quantity on the participant's behalf – with the participant having an imbalance position at 6AM. This position would then be settled at the 6 AM price (probably through an imbalance payment or charge).

This option would maximise potential liquidity by pooling buyers and sellers operating at different locations into a single market. It would also provide counterparties with greater delivery certainty and end-to-end anonymity by leveraging the DWGM's scheduling and balancing process – an advantage over the Wallumbilla Gas Supply Hub The alternate approach of having a supply hub with multiple trading locations (for example at Culcairn, Longford and Iona) would significantly split liquidity, providing participants with less confidence in the price signal and making a liquid futures market almost impossible to achieve. Further, by establishing separate forward markets outside of the DWGM, there will be additional complexity for a participant to ensure that trades are scheduled into the market. We provide further detail on the issues associated with this approach in *Attachment B.*

A forward market integrated with the DWGM would provide the ability to hedge (or lock in) the commodity price and volume for a gas day - it would not hedge against intraday variations such as deviating from your scheduled position. AEMO considers this a different risk that should be hedged or managed separately from a forward commodity product. It is also not consistent with our understanding of how similar European forward markets work where intraday actions undertaken by the system operator to address congestion or surprise events are not able to be hedged by participants through a forward market product that typically converges to a day ahead price. A different and more specific type of hedge product, linked to a flexible supply source, such as LNG, would be more appropriate to managing intraday deviation risk.

In addition to further design considerations the following would be required to implement a forward market:

- Amendments to Part 19 of the National Gas Rules to implement the forward market and create the allowance for a legal framework similar to the GSH's exchange agreement
- AEMO currently has an Australian Financial Services License (exemption) under the Corporations Act, and this would need to be reviewed for the Victorian Forward Market
- Minor changes to GSH settlement and prudential systems
- Changes to DWGM systems to incorporate forward market trades into the DWGM Spot Market

Attachment B – Assessment of alternate market design options

1 Introduction

In this attachment, we provide our preliminary view on the design options in the AEMC's discussion paper. Our recommended package of reform options is provided in Attachment A.

2 Gas trading options (options 3.1 – 3.4)

Our preferred approach is a modified version of option 3.2 where uplift is simplified but surprise uplift is retained. We consider that options 3.1, 3.3 and 3.4 would not enhance the spot market's liquidity and would not be conducive to improved risk management. We provide further detail below.

2.1 Transmission constrained pricing schedule (option 3.1)

A single transmission constrained pricing (and operating) schedule would result in the market price being set by the constrained marginal bid that is required to meet demand. The primary purported benefit of this option is that it provides a single spot price (as ancillary payments and uplift are no longer required), and that this will improve the ability to manage risk. However, we are not convinced that this option will result in an improved ability to hedge prices as it may introduce additional risks that are challenging to hedge especially for those without flexible portfolios (in particular, access to LNG). We outline our concerns with this option below.

The main issue with this model is the additional risks it introduces to the market. As identified by the AEMC, a constrained pricing model would be likely to increase the volatility of pricing materially increasing risks for participants. This is because unlike the current market, where only the constrained quantity of gas is paid at the constrained price, the entire market is priced at the constrained price. This price is likely to be set at the only source of flexible supply in the system – the Dandenong LNG facility[1]. Such a pricing mechanism is therefore likely to result in a wealth transfer from net buyers to net sellers, and will favour participants with LNG capacity.

Without an established contract market to hedge this price volatility risk (such as exists for the NEM), participants will be inclined to take physical hedges which in turn may be negative for traded volume and liquidity. This is particularly the case given that constraints occur intraday but the contract market will likely manage risk against the 6AM price. For smaller players a complete physical hedge (in the form of a GSA) may not be possible and such players could exit the market.

At a minimum, if this option is pursued, a complete review of the market's pricing parameters should be undertaken. In addition, consideration should be given to whether good faith provisions (as exist in the NEM) are required for intraday rebidding especially given potential gaming issues which are outlined below.

AEMO considers that there are two important issues associated with this model that would need further consideration:

1. Firstly, this option is likely to concentrate market power at the Dandenong LNG facility. This facility is fully contracted, and the majority of the contracted capacity is held by only a handful of participants. The impacts of implementing a market structure that concentrates market power in a single facility and to a small number of participants on market participation and liquidity should be considered.
    a. In particular, given the high level of concentration and importance of LNG facility to the constrained market, consideration should be given as to whether the current

[1] Gas typically takes between six to eight hours to physically move from the DWGM's main supply sources to Melbourne. When gas supply is required is within this time period, and linepack is low, the only source of supply close to Melbourne is the Dandenong LNG facility.

contracting arrangements at the LNG facility are appropriate and how access to capacity by new participants at efficient prices could be facilitated.

2. Secondly, we consider that a gaming risk does exist if this option is pursued. The example given by the AEMC on page 27 to indicate that there may not be a gaming risk, does not consider the temporal issues that exist in a gas market and that are catered for by the current market. Leveraging the AEMC's example, under the constrained pricing model, if a participant increases its demand forecast (or uncontrollable withdrawals) this could result in a constraint requiring the scheduling of LNG. If the participant has already had its injections at another location (say Longford) scheduled it may have a positive imbalance and so would benefit from the higher market price (unless it got descheduled at Longford which may not happen if it bids at $0/GJ and has AMDQ) and/or the costs of the constrain would be paid for by another party.

   Under the current market model, this participant would be exposed to surprise uplift for increasing its demand forecast regardless of its imbalance position and so has an incentive to not behave in this way. The forward-looking component of surprise uplift creates incentives for accurate forecasting and not 'surprising the market' (and causing congestion), it is not clear whether the proposed market provides the same incentives. Similar temporal gaming and efficiency issues exist under the Southern Hub model and need to be considered further.

Importantly, under this approach when a constraint binds, requiring the scheduling of more expensive gas this gas is paid for by participants who deviate and/or those who have an imbalance, these participants may not be the causer of the constraint. (particularly as this would be a single market-wide price). In addition, if there is intraday volatility in prices, and additional expensive supply is constrained on and off at lower and higher prices, there could be wealth transfers between participants. For example, where a participant is paying for the constrained gas in one schedule (due to deviating) but not receiving a payment back in a subsequent schedule when the gas is constrained off (due to not having an offsetting deviation). This would be similar to what occurred with intraday uplift and ancillary payments prior to the implementation of AP Flip Flop. The cost-to-cause allocation of congestion and constraint costs would be unlikely to be materially improved under this approach.

Volatile prices due to constrained pricing would also lead to issues associated with the linepack account, particularly if AEMO is 'buying' or 'selling' gas to meet the end-of-day linepack target across volatile prices within the gas day. This cost is currently socialised across withdrawals.

An additional consideration is how ad-hoc schedules would be priced under this approach. Under the current market, an ad-hoc schedule does not directly affect the market price (it is an OS schedule only and may result in ancillary payments and uplift being generated). Presumably when an ad hoc schedule is run, a new price would have to be generated based on the marginally constrained bid that is scheduled. The question then becomes to what period does this price (and what share of injections and withdrawals) apply?

When this option has been previously considered it has been proposed that one way to address the market power and gaming issues associated with the LNG facility being the primary source of flexible supply is to introduce an ancillary service for LNG[2]. While this may beneficial there are two issues with this approach that should be considered:

1. If the LNG facility is removed from the market and is separately priced, this would remove liquidity from the market. It would also potentially reduce participant flexibility to bid in LNG to manage their portfolio needs (as they can now) if capacity has to be held back for an ancillary service. Designing an ancillary market to address both of these concerns is likely to be complicated.

2. Secondly, it is not clear that designing an ancillary service for LNG is likely to result in a material benefit or change over the status quo. This costs of this service will need to be recovered (presumably on a cost-to-cause basis), and as a consequence you end up with a pricing and cost model similar to the current ancillary payments and uplift approach.

[2] By an ancillary service, we assume this will be a separately priced sub-market.

In summary, the implementation of this option would introduce additional risk to the market and its not apparent that it would be to the benefit of consumers.

2.2 Simplified uplift (option 3.2)

We consider that this option may be better characterised as a review of the uplift allocation methodology. We consider that such a review would have merit, as the efficiency of the current uplift allocation methodology has come into question as part of this review. Our preliminary view, which we provide in Attachment A, is that removing both congestion uplift and surprise uplift would result in a loss of efficiency due to removing incentives for participants to forecast their demand accurately. However, we consider that there is merit in reviewing congestion uplift and we consider its removal would improve risk management and market liquidity.

2.3 Discrete schedules (option 3.3)

We do not support this option as we consider that it would introduce additional market complexity and would negatively inhibit inter-regional trade. Firstly, it is not clear that the ability to hedge price (the primary purported benefit of this option) is materially improved. Any derivative product will need to converge to a reference price on-the-day and this price will likely be set somewhere between the discrete 6AM – 10AM price and the discrete 6PM – 10PM price. The multiple firm within day prices will create basis risk when compared to the current futures product that converges to the 6AM schedule price which covers the entire gas day.

If a linepack market is introduced on top of this option, then this will create additional pricing and market complexity. Given the limited amount of useable linepack consideration as to whether the benefits of a linepack market in enabling participants to economically signal for linepack outweigh the costs and additional complexity it would create for the market design.

A second concern with this option is the impact of discrete scheduling and pricing on trade between markets and regions. Under the current market, a participant has an ability to lock in its position in Victoria at the 6AM schedule for the whole gas day. The ability to do this under the proposed model is far less certain as the participant is only able to lock in its position on a four hourly/eight hourly basis. All other markets (and most pipelines) on the east coast operate on a gas day basis. If Victoria operates on a four hourly or eight hourly basis, trading between markets will carry additional risk and complexity (particularly for nominations). For example, injections into the DWGM would be for a specific interval of the day whereas nominations and scheduling of withdrawals from the connecting facility would be on gas day basis.

3 Forward market options (options 4.2 – 4.4)

AEMO is very supportive of introducing a physical forward market to Victoria. A forward gas market would deliver benefits by providing a platform for managing gas market risk and efficient inter-hub gas trading. We see the development of an active forward market as important to aiding liquidity and participation in the spot market as well as support the development of any future derivative hedging products that may converge to a day ahead price struck in the forward market (as opposed to the spot market's price).

3.1 Forward physical trading with the DWGM (options 4.3)

From the options proposed, we support option 4.3 "Forward physical trading within the DWGM". We support the variant of this option that allows participants to bid their forward position into the 6AM schedule. Under this option, by leveraging the DWGM's virtual hub, a single market that pools buyers and sellers operating at different physical locations can develop. This should maximise opportunities to trade, reduce risk by providing firmness to open positions through using the DWGM's balancing mechanism and create trading anonymity – maximising potential liquidity.

Under our proposal (further described in *Attachment A)*, Victorian physical forward contracts would carry an obligation on a trader to deliver gas to the DWGM where title is transferred to their counterpart. Any variation between the transaction volume and a trader's actual delivery would be settled at the spot price.

Unlike a futures contract, traders would need to be a registered market participant with AEMO and would have an obligation to deliver or receipt gas in accordance with their trades.

This option is consistent with the design of the NBP and TTF where delivery of physical forward products is integrated with the virtual hub and would be consistent with a transition to the Southern Hub model proposed by the AEMC in its Draft Report.

We provide further details on this option as part of our proposed package outlined in Attachment A.

3.2 Forward physical trading outside the DWGM (options 4.2)

Option 4.2 "Forward physical trading outside the DWGM", would effectively create several multiple pricing points and markets – with each market tied to a physical location. AEMO has a number concerns with this model and whether it would result in a liquid and efficient forward market. Below is an outline of some of the issues that we have identified with this model.

Promoting liquidity

To promote forward market liquidity, it is important to pool potential buyers and sellers. Under option 4.3 potential buyers and sellers operating across the DWGM would compete at a single trading location, driving liquidity and efficient pricing.

However, under option 4.2 there would essentially be three markets that would be priced separately at each location. This would be expected to reduce participation, and therefore trading liquidity, at each market (due to the need to have a physical position at the market's location). This option would also split the market for the trading of gas between the DWGM and three other hubs. In comparison, a Victorian forward product under option 4.3 would promote competition by concentrating all trades at a virtual hub, promoting trading liquidity and resulting in a reference price that participants have confidence in.

In addition, the further into the future a product trades, the thinner the market and hence the more difficult it is to match pricing expectations of buyers and sellers, making it important to pool together potential buyers and sellers. In a market as large as the US there are many spot trading locations that aid efficient short-term allocation of gas within specific geographic regions, but the Henry Hub is the primary forward market for the US.

It is noted that trading at a specific location outside the DWGM may suit some traders from time to time. These trades could be accommodated under option 4.3 by allowing bilateral physical trades at these locations to be registered and settled through the market (referred to as off-market trades in the Gas Supply Hub). Such an approach would still contribute to information transparency and price discovery as information related to off-market trades is published on the GSH in the same way as screen trades.

In summary, option 4.2 would split liquidity across the various nodes and between Victoria and the rest of the east coast, giving participants less confidence that the price reflects supply and demand conditions. Without confidence in the price, participants will be reluctant to trade and the benefits of liquidity to the market will not materialise. Liquidity breeds liquidity and this makes it important to concentrate as many trading entities and trades as possible at a single point. Splitting liquidity across multiple points in relatively close proximity does not appear to be consistent with the COAG Energy Council's Gas Market Vision.

Delivery arrangements

Under this proposal the buyer would need to receipt gas and then have that gas scheduled for injections into the market – a further administrative step over option 4.3. Buyers would also need to be set-up to receipt gas at each of these potential locations, requiring contractual negotiations and amendments. Standardised arrangements for transferring title between traders would also need to be developed and put in place at each location.

In comparison to option 4.3, trades would be delivered through a bilateral process. In the event the volume a trader actually delivers varies from their transaction volume then the counterparties would need to bilaterally true up the trade through a physical or financial reconciliation.

In comparison, option 4.3 benefits from the allocation and balancing arrangements in place for the DWGM with any imbalance settled through the market – this would not be the case under option 4.2. Further, the integrated approach would simplify the delivery process and allow counterparty details to remain anonymous throughout.

Risk management product
Pricing of the products outside the DWGM would not converge to the spot price and as such, it would not be effective in managing market risk in the DWGM. In addition, this proposal would not complement the current Victorian futures contract. The physical forward product should have the same definition so that it can be used by traders to manage risk associated with their futures positions (or vice versa).

Further, creating multiple forward prices across different nodes is unlikely to result in the development of any new derivative products, which, in other gas markets, typically converge to a single liquid day ahead price that participants trust. Multiple prices at different points would create significant basis risk for a derivative product making its emergence unlikely and an expectation that three separate well-traded futures products will emerge is unrealistic for a gas market the size of the east coast.

Capacity rights and implications for buyers
This option may suit a seller that does not want to participate in the DWGM. However, complementary reforms of capacity rights and spot market design would aid the participation of producers and inter-state traders in the DWGM.

Under this option, there would be a requirement to receipt gas outside the DWGM and have that gas scheduled into the DWGM and this responsibility would fall on retailers and end users. Rather, AEMO considers it more efficient for a seller to manage the injection into the market as they know in advance the timing and location of injections and would be able to pair this activity with the procurement of any other transportation and pipeline services required to bring their gas to market.

3.3 Forward physical trading with a net daily gas market (option 4.4)

Option 4.4 “forward trading with a net daily gas market” would be a substantial undertaking involving a complete redesign of the on-the-day scheduling and pricing arrangements which are likely to be costly. Given the parallels between this option and Southern Hub model, it would be more appropriate as a transitional step to that option – however the costs of implementing option 4.4 as a transitional step may still be too prohibitive to be worthwhile.

4 Capacity options (Options 5.1 – 6.5)

4.1 Exit AMDQ and secondary trading of AMDQ (options 5.2 and 5.3)

An issue raised with the current market carriage framework is the ability to acquire tie-breaking rights at controllable withdrawal points. We consider that option 5.3, introducing exit AMDQ, merits further consideration. Our proposal would be to create separate entry and exit AMDQ, the creation and allocation of which would be guided by a statutory planning standard. The quantity of exit AMDQ would need to be sculpted as the capacity at most controllable withdrawal points is a function of the system demand – this would be informed by the planning standard. In practice, exit AMDQ would provide a participant with a tie-breaking right at a controllable withdrawal point, entry AMDQ would provide the same right (as it does now) at injection points. The ability to trade entry and exit AMDQ via secondary market (5.2) should also be considered as part of this reform.

The implementation of option 5.3 would not preclude the implementation of option 6.2, to have “Firmer financial capacity rights” associated with AMDQ. Though it should be noted that there are considerable complexities that would have to be worked through under both approaches the AEMC have put forward. We agree with the AEMC’s analysis on the challenges of setting an appropriate tariff differential outlined on page 75, and raised similar concerns in our October 2015 submission.[3] We provide further information on some of the complexities with introducing financial rights later in this attachment.

4.2 Firmer AMDQ (Option 6.1)

When a constraint binds, this option proposes to provide greater firmness to injection bids that are scheduled below the market price over bids without AMDQ. While this option would improve the firmness of AMDQ, it is likely to be complicated to implement and in reality may be of only limited benefit in providing additional firmness in scheduling. We provide further thoughts below.

It is not clear that this model is consistent with the constrained pricing model. Under the constrained pricing model, if a non-firm bid is de-scheduled below the market price, then this would result in the need for another bid to be scheduled elsewhere which could change the market price (which is inconsistent with this model's proposal).

This mechanism would likely require a substantial overhaul to the market clearing engine. With a PS and OS, complex scheduling interactions would be required to facilitate a relative prioritisation of bids with AMDQ over bids without AMDQ when both bids are below the market price set in the PS. In the OS, bids would need to be divided into bids with AMDQ and bids without AMDQ at system injection point and close proximity point level. After the initial prioritisation of AMDQ bids, any remaining quantity that needs to be allocated from the constraint would need to be allocated to bids without AMDQ in price order. Additional tie-breaking logic would be required to tie-break equally price bids with AMDQ and equally priced bids without AMDQ. Interactions between constraints and bids at system injection point and close proximity point level would also need to be managed.

Further complexity would also be created by the need to manage variable counter flows between schedules, which would change the scheduled quantities with and without AMDQ. A further issue to be resolved is whether AMDQ is applied to a participant's bid stack automatically (presumably based on the lowest price bids first) or whether an interface is required for participants to manually assign AMDQ to each bid step (a further complexity).

The value of the proposal is also uncertain. While it would provide firmness to bids under the market price, participants would still have to bid (for injections) below the market price to receive this firmness. At a point that is constrained, for which there is a lot of competition for capacity and/or if the market price is volatile, the incentive to bid at the minimum market price will likely still remain to maximise the participants' scheduling certainty. If a point is not constrained, then this approach provides no additional firmness over the current scheduling arrangements.

4.3 Financial capacity rights (option 6.2)

While the implementation of financial capacity rights in the manner described in option 6.2 may be possible, it would add considerable complexity to the market design. Under this option, an STTM capacity payment mechanism could be introduced to compensate firm shippers who are not scheduled ahead of non-firm shippers when a pipeline is constrained.

First is not clear that this model would work under a market with an unconstrained pricing and constrained operating schedule. Transportation constraints are only applied in the OS, the trigger for a capacity payment would probably have to be the application of a transmission constraint (NFTC) in the OS only. However, the market price (which is used to determine the capacity price) is in the PS and will be an unconstrained price that does not reflect transportation constraints and so this model may not work. Further, the STTM (unlike the DWGM), has a simplified network model with one or two pipelines and bidstacks (that are used to set the capacity price). In the DWGM, there would need to be the ability to allocate capacity payments across multiple bid stacks at a close proximity point (one for each facility), potentially creating multiple capacity prices.

In addition, the intraday nature of the market would add a further layer of complexity. Capacity constraints as well as market prices change throughout the day. In the event where a capacity constraint is binding in the 6 AM schedule but not in a later schedule, there would be a positive

[3] AEMO, *Submission to DWGM Discussion Paper*, p.5, 12 October 2015.

capacity payment followed by a negative capacity payment. If the intraday prices are different then there would be a difference in these positive and negative capacity payments. Of course participants' scheduled positions also will change across the day, driven by changes in bidding, demand forecasts and constraints. These changes would affect the quantum and allocation of capacity payments, for example if a firm shipper is not initially scheduled but is scheduled later in the day. The need to allocated and reallocate these capacity costs efficiently would likely result in the need for an allocation model at least as complex as uplift.

Once the complexities and associated costs have been worked through, we consider this model would be unlikely to deliver a net benefit.

4.4 Zonal pricing and residue rights (Option 6.3)

Option 6.3, to introduce "Zonal pricing with settlement residue rights" is not supported at this stage. This model would considerably increase the market's complexity and as identified by the AEMC has the potential to split liquidity by introducing a number of zones. The AEMC have identified that "the key rationale for this approach is that it provides incentives for market led investment in inter-zonal pipeline capacity.[4]" We agree that this is unlikely to occur as the rights provided under this model are not fully firm, and will be challenging to define given the DWGM's meshed network. Creating additional pricing zones, which would be likely to split liquidity, does not appear to be consistent with the COAG Energy Council's gas market vision.

As part of our proposal, we have recommended that a constrained pricing mechanism (similar to the pipeline flow constrained pricing mechanism in the STTM) should be considered for the DWGM. Such a pricing mechanism allows participants to economically trade above the market price at a flow direction constrained point when the market price has been set at another location. If this mechanism can be implemented, it would deliver a locational price when a facility is flow-direction constrained, achieving one of the primary benefits of zonal pricing (potentially on a more granular) level without undermining the liquidity of the hub. Further detail on this mechanism is provided in Attachment A.

4.5 Contract carriage models (Option 6.5)

It is not clear how applying the proposed contract carriage model to the DTS is feasible or that is it would deliver a net benefit. The options represent a substantial overhaul to the existing arrangements, and would likely be considerably costly to implement. In effect the contract carriage options sacrifice most of the efficiencies in scheduling and trading provided by the current DWGM in order to provide firmer capacity rights. In particular, we consider:

- Sub option 1 which has multiple system operators (APA for contract carriage pipelines and AEMO for market carriage pipelines) is not operationally viable given the interconnectedness of the network. For example, how would a constraint within the APA network that needs to be relieved using supply from (or transiting) the AEMO network be managed, particularly if there are conflicting priorities between the two networks?
- Defining the rights and pathways under a contract carriage model would be complex given the meshed nature of the network and may undermine trading and the benefits of the virtual hub by making gas less fungible.
- It is not clear how trading between the DWGM and non-DWGM system could be facilitated given they both run on different market frameworks and potentially different contract rights. The inability to trade between these two systems would reduce the size of the wholesale market and inevitably impact trading volume and liquidity.
- The proposal may negatively impact retail contestability due to the opt-in/opt-out nature of demand under the proposal. It is not clear how this would work with a contestable retail market. For example, if a customer churns from a non-AEMO retailer to an AEMO retailer but AEMO has not acquired sufficient capacity to supply that customer, what happens to the churn, would it have to be blocked?

[4] AEMC, *Alternative Design Options,* p.79, March 30 2017

- It is not clear how AEMO would forecast its capacity requirements under this approach. For example, on a peak day almost all capacity would be required to meet system demand. This would mean that there is little ‘non-DWGM’ capacity available to be contracted for (that would sit outside the DWGM) which brings into question whether there is an actual net benefit from implementing this proposal.