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Australian Energy Market Commission
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Lodged (online): www.aemc.gov.au/Contact-Us/Lodge-a-submission

East Coast Wholesale Gas Market and Pipeline Frameworks Review: Public Forum Paper

The Energy Supply Association of Australia (esaa) welcomes the opportunity to make a submission to the Australian Energy Market Commission's (AEMC) East Coast Wholesale Gas Market and Pipeline Frameworks Review Public Forum Paper.

The esaa is the peak industry body for the stationary energy sector in Australia and represents the policy positions of the Chief Executives of 37 electricity and downstream natural gas businesses. These businesses own and operate some $120 billion in assets, employ more than 59,000 people and contribute $24.1 billion directly to the nation's Gross Domestic Product.

The east coast gas market is in a state of transition. Production costs are rising, political uncertainty is hampering onshore gas development in a number of regions and most notably, new demand from the LNG export industry is changing market dynamics. To provide an idea of the size of the export volumes anticipated, in 2016 LNG exports from the east coast are projected to exceed 1,200 PJ. This compares with total east coast domestic demand of around 570 PJ.

Given the size of this competing source of demand, it is clear continued resource development will be the key to alleviating any supply/pricing pressures for domestic market participants over time. But flexible downstream gas market arrangements will also be essential to facilitate access to supply, drive efficiency gains and enhance competition across the broader east coast gas market. While the Association considers the facilitated markets and pipeline transportation arrangements are generally working as intended, there is clear scope for improvement in this regard.

The AEMC's gas market review provides an important opportunity to investigate these issues and consider how best to facilitate continued market development. In this context, the esaa is supportive of an incremental approach to gas market reform that has regard for existing contracts. With regard to wholesale gas market and pipeline transportation arrangements, key to this approach will be: minimising the costs and risks associated with participating in the facilitated trading markets; and pursuing enhanced market transparency and contract standardisation in support of industry-led pipeline capacity trading initiatives.

The Association's detailed response to the specific questions raised by the AEMC is provided in Attachment 1. In developing and mapping out any future market reforms, continued industry engagement is essential. Further, the decision to proceed with any changes to current arrangements should ultimately be informed by robust cost-benefit analysis.

Any questions about our submission should be addressed to Shaun Cole, by email to shaun.cole@esaa.com.au or by telephone on (03) 9205 3106.

Yours sincerely

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Attachment 1

Facilitated markets

Question 1: Given their performance to date, are the existing markets able to facilitate transactions required to manage current conditions?

The east coast gas market is in a state of transition. Production costs are rising, political uncertainty is hampering onshore gas development in a number of regions and most notably, new demand from the LNG export industry is changing market dynamics. To provide an idea of the size of the export volumes that are anticipated, in 2016 LNG exports from the east coast are projected to exceed 1,200 PJ. This compares with total east coast domestic demand of around 570 PJ.

Given the size of this competing source of demand, it is clear continued resource development will be the key to alleviating any supply/pricing pressures for domestic market participants over time. But flexible access to downstream markets will likely become increasingly more important, particularly given the desire for more transparent and shorter-term price signals.

The facilitated markets have an important role to play in this regard. They provide a transparent market-based mechanism for managing daily imbalances between injections and withdrawals. Market participants have also suggested they assist with facilitating new entry.

But these benefits do not come cheap. The facilitated markets impose relatively high costs per GJ traded – around $1/GJ for the Short Term Trading Market (STTM) and 50c/GJ for the Declared Wholesale Gas Market (DWGM) based on an assessment of volumes traded, deviation costs and market revenue requirements.[1] The key factor driving these relatively high costs is the low volume of gas traded, with market participants generally seeking to closely match their own injections and withdrawals to minimise exposure to significant financial risks that cannot be hedged.

To improve trading and liquidity and ensure the facilitated markets deliver value to market participants in the future, reducing transaction costs and minimising the pricing risks associated with participation is essential. These issues are discussed in further detail below.

Question 2: Will the current market framework be able to facilitate transactions that may be required to meet future conditions?

Please see response to *Question 1 (Facilitated Markets)*.

Question 3: Are there barriers to using wholesale markets, for instance for new entrant retailers or for large users wishing to participate directly in the markets?

The facilitated markets provide such participants with access to gas in the initial phase of market entry, allowing them to develop the experience and understanding of

[1] Deloitte – Report for the Energy Supply Association of Australia, "Assessment of the East Coast gas market and opportunities for long-term strategic reform", May 2013.

demand requirements before committing to long-term bilateral contracts for supply and transportation. In this regard, the DWGM is generally viewed as being more conducive to new market entry given the size and maturity of the market as well as the pipeline carriage arrangements. But long-term contracts for gas supply and transportation (outside of the DWGM) are ultimately required to manage the significant price risk associated with operating in those markets.

This is not to suggest the reliance on long-term bilateral contracting for supply/transportation is not appropriate. Rather, that the ability of market participants (and new entrants) to rely purely on the facilitated markets for gas supply will continue to be impeded while ever they create significant price/supply risk.

Question 4: What opportunities are there for improved integration between the markets?

Differences between the DWGM and STTM can potentially increase costs for participants operating across multiple jurisdictions. Investigating opportunities to deliver greater consistency between those markets is therefore a positive initiative. As a first step the Association considers there is merit in examining:

- the creation of a single gas day, noting there are currently three gas day start times across 4 different hubs/regions;
- the consolidation of prudential requirements, with consideration also given to the Wallumbilla gas supply hub (GSH) and National Electricity Market (NEM); and
- harmonisation of gas market parameters.

The extent to which these market inconsistencies increase costs for gas market participants is unclear. Examination of these issues should therefore include a broad assessment of materiality and also consider the extent to which any proposed change is appropriate in the context of each market. This is particularly important in relation to the harmonisation of gas market parameters, since key differences in market design may mean it is inappropriate to streamline specific market parameters.

The Australian Energy Market Operator’s (AEMO) Gas Wholesale Consultative Forum (GWCF) should be able to provide useful guidance in this regard, given some of these issues may have already been considered within that group.

Short Term Trading Market

Question 1: Are the original objectives for the STTM still relevant and compatible with the new Council visions? How have stakeholders’ experience with the STTM corresponded to initial expectations?

Please see response to *Question 1 (Facilitated Markets)*.

Question 2: Are all STTM hubs (Sydney, Adelaide and Brisbane) delivering value to market participants?

The facilitated markets are generally considered to be beneficial to the extent they provide participants with a market-based mechanism for managing short-term trading positions. Where trading in these markets is impeded through general market complexity or other factors, it is likely their overall value is diminished. As noted in response to *Question 1 (Facilitated Markets)*, the STTM is actually quite costly on a $/GJ traded basis.

To encourage greater participation/competition and improve the overall value of the STTM, it is essential to reduce the level of pricing risk in the market. In the STTM there are a number of complex charges/payments associated with market deviations that cannot be effectively hedged. These include charges/payments relating to: market operator services (MOS); short and long term deviation payments; contingency gas (which has not been required to date); and the settlement surplus or shortfall that is allocated at the end of each month.

The Association is supportive of refining these market design elements such that each gas day is self-contained. Ideally, simplifying market pricing arrangements in this way would improve market participants' ability to understand their risk exposure on any given gas day. It would also allow for the transfer of complexity from the primary market into the secondary market and foster the development of derivatives to hedge risk.

It should also be noted that the Brisbane hub suffers from structural limitations beyond those discussed above. This includes: a reliance on a single transmission pipeline, the Roma to Brisbane Pipeline (RBP); the inability to purchase gas from the hub unless a transportation contract on the RBP is held; and the market design assumption that there are no constraints within the hub when this is clearly not the case. As discussed in response to *Question 2 (Wallumbilla Gas Supply Hub)* below, the evolution of the Wallumbilla GSH could further diminish the value of/need for the Brisbane hub in the future.

Question 3: What design features of the STTM could be improved to reduce costs and improve efficiency? (e.g. is there a role for intra-day trading?)

Please see response to *Question 2 (Short Term Trading Market)*.

Question 4: Given that most gas supply is bilaterally contracted, is it realistic to expect that prices in the STTM will signal underlying supply and demand conditions? If not, what is the role and value of STTM within the broader gas market framework?

Please see response to *Question 2 (Short Term Trading Market)*.

Wallumbilla Gas Supply Hub

Question 1: Is Wallumbilla adding value to the way participants manage their gas portfolios and what directions should the development of the market take?

The Wallumbilla GSH has performed better than expected since it commenced operations on 20 March 2014. Trading at the RBP location averaged around 4% of RBP flows in late 2014 and the total number of registered trading participants is expected to reach 12 in 2015. A monthly product and ASX futures products are also set to be implemented in the first half of 2015.

The value of the Wallumbilla GSH will be enhanced over time through greater market liquidity and participation. As it currently stands, participation at the Wallumbilla GSH is limited to physical traders only. But AEMO's GSH reference group has initiated a process that could open trading opportunities for non-physical participants such as financial institutions. This includes assessing the benefits of developing a single trading product at Wallumbilla, including the balancing services required to facilitate the single product.

The Association is supportive of this process with a view to improving market liquidity. The decision to proceed with any reform option should ultimately be informed by an assessment of overall costs and benefits.

Question 2: How does trading at Wallumbilla impact on trading in other wholesale markets?

As discussed, there are a number of issues associated with the Brisbane STTM hub that constrain the level of trading and overall value of the hub. These include the hub's reliance on a single gas transmission pipeline (the RBP) and relatively flat demand. Given the RBP passes through Wallumbilla, evolution of the Wallumbilla GSH to incorporate a single trading product and balancing services would allow balancing to take place further up the RBP. This could further diminish the cost effectiveness of the Brisbane hub.

Question 3: Would the establishment of a GSH at Moomba facilitate additional trade? Would a Moomba GSH impact on liquidity at Wallumbilla?

A Moomba GSH has the potential to facilitate improved participation and liquidity. It would provide a trading platform for those participants situated off the Moomba to Adelaide Pipeline and Moomba to Sydney Pipeline that do not have an interest in trading at Wallumbilla. This would provide market participants with greater optionality and potentially assist with efficient balancing of market participant portfolios.

AEMO's GSH reference group is currently exploring the value of this development. As part of any assessment, it will be important to ensure the new hub does not impose additional costs on existing GSH trading participants through increased exchange fees or increased variable transaction fees for the trading products.

Question 4: How useful is the information provided by the Wallumbilla hub to market participants and what additional information could be provided to improve accuracy and transparency at the GSH?

Please see response to *Question 1 (Wallumbilla Gas Supply Hub)*.

<u>The Declared Wholesale Gas Market</u>

Question 1: Are the original objectives and rationale for the DWGM relevant and compatible with the Council's vision?

Please see response to *Question 1 (Facilitated Markets)*.

Question 2: Is investment in the Declared Transmission System (DTS) occurring in an efficient and timely manner? Or are there limitations with the current investment and/or regulatory framework?

Market carriage models generally have a number of positive attributes. This includes open access, relatively low barriers to entry and exit and efficient network utilisation. But a lack of clarity around the definition of transmission capacity rights can lead to challenges in allocating and contracting and weak incentives for infrastructure investment.

For the DTS, concerns have been raised in relation to the efficiency and timeliness of investment. This anomaly arises because a private investor on the DTS is not able to gain exclusive firm capacity rights on the pipeline that it has funded. Investment decisions in the DTS are therefore driven by the regulatory process, which may be less efficient and timely than relying on market driven investment decisions.

Question 3: Do the DWGM arrangements inhibit the transportation of gas between the DTS and interconnected pipelines?

It is understood issues have previously been raised over the need to participate in the DWGM in order to export gas via the DTS. The ability to export gas into NSW was highlighted as a specific concern, given withdrawal capacity at Culcairn is more susceptible to curtailment than other forms of demand.

The extent to which these issues persist is unclear. In general, trade decisions are generally dictated by the availability/value of pipeline capacity and the price competitiveness of any gas that would be offered in another region. Capacity expansions and greater transparency in AEMO's operations at Culcairn have alleviated any immediate concerns over exports into NSW. There are also opportunities to bypass the DWGM by exporting gas from the Gippsland Basin to NSW via the EGP and from the Otway Basin via the SEA Gas Pipeline.

Question 4: How could the market design be amended to provide additional tools for participants to manage price risk and volume risk in the DWGM?

Similar to the STTM, risk in the DWGM is not embedded in a single daily market price. Reducing the complexity of ancillary payments and uplift charges and linking them to the market price could improve participants' ability to assess and manage risk. This would likely improve the value and uptake of risk management products such as the ASX Victorian Wholesale Gas Futures product currently available and deliver greater market transparency.

Transmission pipelines

Question 1: Are the original objectives of the gas access regime still relevant and compatible with the Council's vision?

Transmission pipelines are highly capital intensive investments that require a substantial level of debt gearing. As such, long-term foundation contracts have generally been required to provide revenue certainty to underpin investment in a transmission pipeline project. While this may frustrate incremental demand growth to some degree over the short term, it does not appear to have been a fundamental constraint to the development of the industry. Significant investment in pipeline capacity has occurred, with the current framework providing a reasonable balance of end-user protection with service provider protection and incentives. These arrangements have also provided for a transmission network that is relatively free of constraints.

On this basis, the Association believes the original objectives of the gas access regime are still relevant and compatible with the Council's vision. But it is recognised that changes under way in the market are likely to test the efficacy of current regulatory arrangements, particularly as they relate to facilitating access to short term capacity trades.

Question 2: Is the current low number of covered transmission pipelines a cause for concern or a measure of competition?

Tariff uncertainty due to prospective near-term regulatory reviews creates significant risk for both pipeline operators and financiers. As such, the light handed or no coverage options are seen to be important features of the regulatory environment. In particular, the no-coverage option for greenfield pipelines is generally viewed as an option that encourages pipeline projects to be built.

It is acknowledged there are some potential negatives associated with this regulatory option from the perspective of third parties. New transmission pipelines authorised under the greenfield pipeline arrangement may result in no service being available to third parties – pipelines are generally sized efficiently to satisfy the maximum need of the related end-use project for the least amount of capital. There is also a general reduction in transparency and certainty for prospective shippers seeking access to non-covered pipelines due to the absence of standard reference tariffs and associated terms/conditions.

Nonetheless, it is not clear that the no-coverage option creates a fundamental constraint to the development of the industry. The east coast market has become reasonably well connected with gas transmission pipelines over the past 10 years. Key demand centres are now served by multiple transmission pipelines from multiple gas basins. Aside from simply increasing inter-basin competition, this interconnection creates a degree of competitive tension, with most unregulated transmission pipelines competing with other pipelines to supply a demand centre.

Question 3: Are there impediments to short term trading of pipeline capacity trading (i.e. why is secondary trading not occurring?) If so, how should these be best addressed?

The east coast gas market has not developed a liquid and flexible market for secondary trading of transmission capacity. The absence of such a market does not necessarily imply there is a market failure or that investment has been inefficient. A lack of secondary trading could be reflective of a number of factors, including the fact that gas pipeline capacity is not homogenous, with different terms and conditions and operating environments.

Nonetheless, flexible and transparent access to pipeline capacity is important for the development of a liquid and transparent commodity market. Where access to capacity is impeded, this creates the risk that the incremental benefits of more flexible short-term trades are missed, the value of which may grow as market dynamics continue to evolve.

Addressing this desire for more transparent and shorter-term price signals in an established but evolving market is not without its challenges. There are risks to be considered where the property rights of existing capacity holders – established under pre-existing long-term contracts – are potentially compromised. Further, it is not clear that implementing some form of mandatory trading would deliver the efficiency gains necessary to justify such significant intervention.

The 'trade facilitator' model recently developed for the South West Queensland Pipeline, RBP and Queensland Gas Pipeline is an important initiative in this regard. It demonstrates the ability of industry to respond to changing market needs in a targeted and light-handed manner, a key benefit of which is avoided regulatory intervention and unnecessary costs.

There is scope for initiatives such as this to continue to evolve, potentially encompassing more pipelines and providing more standardised products to assist with efficient identification and execution of capacity trading opportunities. On this basis, an incremental approach to reform that has appropriate regard for existing contracts is sensible. Such an approach provides a better balance of risks/benefits relative to more heavy-handed reform options and would likely be consistent with supporting industry-led reform.

The COAG Energy Council's agreement to pursue enhancements to information provision and standardisation of contractual terms and conditions for secondary capacity trading is a positive step in this regard. These reforms were informed by extensive stakeholder consultation and an assessment of the costs/benefits of a suite of different options. Collectively, they will assist with improving market participants' awareness of capacity trading opportunities and reduce the transaction and coordination costs associated with their execution.

Noting the COAG Energy Council's prosed reforms are yet to be implemented, it will be important to allow them sufficient time to take effect before additional interventions are considered.

Question 4: Does the increasingly interconnected nature of gas pipelines and markets on the east coast form a driver for greater harmonisation of regulatory arrangements (e.g. a single carriage model or greater integration of market and pipeline frameworks)?

Please see response to *Question 1 (Transmission Pipelines)*.

Question 5: How useful is the information provided on the Bulletin Board to market participants and what additional information could be provided to facilitate secondary trading?

The esaa is supportive of efforts that increase the availability of gas market information. AEMO's recent initiatives to improve short and long-term market information transparency through the Gas Statement of Opportunities, the National Gas Forecasting Report and Bulletin Board redevelopment are important in this regard. Collectively, they provide high-quality and publicly available information on the real-time operation of the east coast gas market and the longer-term outlook for supply and demand.

In considering where additional information could potentially be provided, it is important to note that increased information is only of value if it addresses relevant gaps in the market. Information that is not appropriately targeted, either with respect to the type or frequency of reporting – may ultimately create a reporting burden for little discernible benefit. There are also confidentiality concerns that must be considered where the publication of highly disaggregated information risks directly revealing commercially sensitive information relating to individually negotiated bilateral contracts.

The COAG Energy Council's Enhanced Pipeline Capacity Information consultation paper touched on a number of these issues and examined the appetite for improved information across a number of different areas. A brief summary of the Association's response to the consultation paper is provided below. Given the relevance of this process to the AEMC's study, there is merit in liaising with the COAG Energy Council on this issue, or at least monitoring the outcomes of the consultation process.

Pipeline capacity and flows

There is value in exploring the provision of enhanced firm/non-firm pipeline capacity and flow data. This would assist with overcoming current data limitations relating to the publication of aggregate nominations and registered capacity on the National Gas Market Bulletin Board (NGMBB) and provide a more accurate reflection of available capacity and gas flows over time. The level of granularity and frequency with which this data is reported must be carefully considered though, given commercial sensitivities and the cost of proving information at more frequent intervals.

Operational pipeline capacity

Enhanced operational pipeline capacity information will be important to address information asymmetries and provide a clearer outlook of future pipeline capacity. New information requirements for short and medium-term operational pipeline capacity were introduced on 8 January 2015. This included: implementing a new-medium-term capacity outlook, utilising existing maintenance reports that are created and provided by facility operators to their shippers; and increasing the short-term capacity outlook from three to seven days.

The Association considers it premature to consider alternative arrangements relating to the provision of medium and short-term capacity information until these recent changes have been given sufficient time to take effect.

Detailed facility and large user information

Information relating to relevant facilities and large users may provide value to market participants seeking a more accurate picture of gas supply/demand conditions. But the extent to which this information is necessary to inform capacity trading is less clear, particularly in the event more detailed capacity and flow data is made available. Publication of this data also risks revealing commercially sensitive information.

Beginning-of-day line-pack

There does not appear to be consensus amongst stakeholders as to the usefulness of beginning-of-day (BOD). While BOD line-pack information may theoretically assist in providing a more complete picture of short term system adequacy, it is not clear the current pipeline adequacy flag system is insufficient. The extent to which this additional information is relevant from a capacity trading standpoint also remains unclear.

Secondary capacity trades

A significant proportion of secondary capacity trades currently occur off market. This is achieved largely via bilateral bare transfer arrangements as well as other more complex product offerings. The esaa does not believe it is appropriate to enforce mandatory reporting of these confidential arrangements and considers there may be limited benefit in trying to capture such information retrospectively. A more suitable approach is to continue to address information gaps and support the development of industry-led initiatives such as the trade facilitator model.