26 March 2015

Mr John Pierce
Chair, Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

Lodged online at http://www.aemc.gov.au/Contact-Us/Lodge-a-submission?nodeid=26713

Dear Mr Pierce

RE: East Coast Wholesale Gas Market and Pipeline Frameworks Review

ERM Power Limited (ERM Power) welcomes the commencement of the East Coast Wholesale Gas Market and Pipeline Frameworks review and the opportunity to provide our comments to the Australian Energy Market Commission (AEMC).

About ERM Power Limited

ERM Power is an Australian energy company that operates electricity generation and electricity sales businesses. Trading as ERM Business Energy and founded in 1980, we have grown to become the 4th largest electricity retailer in Australia, with operations in every state and the Australian Capital Territory. We are also licensed to sell electricity in several markets in the United States. In addition, we commenced retailing gas to large customers in 2015. We have equity interests in 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, both of which we operate.

Within the recent twelve months, ERM Power has become a market participant in the Victorian Declared Wholesale Gas Market (DWGM), the Brisbane Short Term Trading Market (STTM) and the Wallumbilla Gas Supply Hub. We are pleased to provide our comments on the facilitated trading markets from the perspective of a new entrant and share our views on some of the key issues that we believe are creating barriers to entry and adversely impacting competition.

Please contact me if you require further information or would like to discuss any of the matters raised in our submission.

Yours sincerely

[signed]

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ERM POWER SUBMISSION: EAST COAST WHOLESALE GAS MARKET AND PIPELINE FRAMEWORKS REVIEW

PRELIMINARY COMMENTS

ERM Power is supportive of the COAG Energy Council's vision for Australia's future gas market, although we consider that the long term interests of gas consumers with respect to the price of gas (consistent with the National Gas Objective) should form a component of the vision statement.[1]

ERM Power also supports the initial set of criteria that the AEMC has indicated it will build upon when developing its assessment framework. This includes an assessment of whether the market arrangements are –

- Imposing inefficient or unnecessary costs on parties *(Outcome 1)*;
- Exposing parties to risks that are not allocated efficiently or cannot be effectively managed *(Outcome 2)*;
- Impeding efficient investment decisions *(Outcome 3)*;
- Acting as a barrier to entry or otherwise deter competition *(Outcome 4)*; and
- Failing to provide timely and accurate information required by the market.[2] *(Outcome 5)*

As we outline in our submission, ERM Power's view is that there are several features of the current arrangements that are leading to the above adverse outcomes and hindering the achievement of COAG Energy Council's vision and the National Gas Objective.

A. DECLARED WHOLESALE GAS MARKET (VICTORIA)

ERM Power strongly welcomes a review of the Declared Wholesale Gas Market (DWGM). In our view the DWGM design is no longer fit for purpose and contains significant deficiencies that are promoting outcomes contrary to the COAG Energy Council's vision for Australia's future gas market and the National Gas Objective. We agree with the findings of earlier reviews that identified issues such as market inconsistencies, inadequate investment signals, limitations of existing capacity instruments, ineffectiveness of financial hedging products, complexity of the market arrangements and difficulties in exporting gas, as areas requiring further attention.[3]

We appreciate the opportunity to provide our comments on the DWGM as follows.

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[1] The Council's vision is for the *"establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities",* COAG Energy Council, Australian Gas Market Vision, December 2014. The National Gas Objective (section 23 of the National Gas Law) is to "*promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, qualify, safety, reliability and security of supply of natural gas*".

[2] AEMC Public Forum discussion paper, pg.3.

[3] AEMC Public Forum discussion paper, pg.7.

A1. Congestion uplift allocation methodology fails to allocate costs to their cause and penalises small participants/new entrants

The current method of recovering part of the cost of ancillary payments through the allocation of congestion uplift, is not on a cost to cause basis and inequitable. While in the medium to longer term we would recommend a full review of the entire ancillary payments/uplift charge/AMDQ regime, we believe that the specific issues raised here should be addressed immediately and as a priority.

Background

Under the current market design, if additional gas is needed during the day and consequently scheduled by AEMO out of bid-merit order above the market price, the suppliers of such additional gas (typically LNG from the Dandenong Storage Facility) will be paid ancillary payments to compensate them for the difference between the market price and their (higher) bid price. Out of merit order LNG can be required to support system security in response to supply/demand side "surprise" events such as an unexpected increase in demand driven by sudden cold weather, change in consumption of a large load or a production facility failure. AEMO has also indicated a likelihood of an increased requirement for out of merit order LNG from winter 2015 onwards, to support additional export flows from Culcairn to NSW.[4]

The cost of ancillary payments is recovered from participants via uplift charges, which is allocated in accordance with a complex methodology. The methodology has been described as being on a cost to cause basis, for instance, according to AEMO's *Overview of the Victoria Gas Market*, section 5.7.1:

> *"As far as practicable, uplift charges are allocated to those Participants whose actions contributed to the generation of the ancillary payments".*

As explained below, ERM Power disagrees with the assertion that the current cost allocation methodology, particularly in the way in which congestion uplift is assigned, allocates costs to their causers.

Congestion uplift allocation methodology does not allocate costs to their cause

When ancillary payments are generated, a portion of the total cost is always allocated as congestion uplift with the residual being allocated as surprise and common uplift, regardless of the nature of the event that has caused the cost.[5] Congestion uplift is allocated to those who don't have a congestion uplift hedge in place. A congestion uplift hedge requires AMDQ or AMDQ Credit Certificates (collectively we refer to these instruments as AMDQ) and a supporting injection (that matches the zone associated with the AMDQ), and the market participant must have generated this hedge in AEMO's systems.[6]

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[4] *"Increased Likelihood of LNG Requirements in the Victorian Declared Transmission System from Winter 2015, 10/06/2014"* (part of 10/06/2014 GWCF meeting pack)

[5] We acknowledge that there is provision for DTSSP congestion to be allocated to the DTS Service Provider where it has not complied with the service envelope agreement however we are not aware of any time when this has actually occurred.

[6] This is a simplified explanation. In practice AMDQ is converted into AMIQ, so that the hedge is generated on an interval basis.

ERM Power finds it difficult to see how this methodology allocates costs to their cause. The ownership/existence of AMDQ, a matching injection, and the action of generating the uplift hedge in AEMO's systems, makes no difference to whether out of merit order gas is required at any time.

Consider a retailer who has been scheduled to inject a quantity of gas out of the South West Pipeline, has no SWP AMDQ Credits (despite having AMDQ from its customers). If in the scheduling interval, out of merit order LNG is required (e.g. to support flows out of Culcairn) and even if this retailer injects the quantity it has been scheduled to inject, and withdraws exactly as per its demand forecast, under the current market design, it will incur congestion uplift charges, despite the fact that this participant's actions are completely unrelated to the cost and it has followed its operational schedules perfectly.

The AEMO Technical Guide to the Victorian Declared Wholesale Gas Market (2013) describes congestion uplift as being "*charged to MPs who* ***cause system congestion*** *because their scheduled withdrawals exceed their AMIQ uplift hedge*" (page 86).

We think that this statement is misleading and inaccurate. For this statement to be true, it must be the case that if all market participants had congestion uplift hedges in place, there would never be any system congestion or out of merit order gas required. We would argue that even if every single market participant had congestion uplift hedges in place, out of merit order gas would still be required from time to time to deal with unanticipated events, and from winter 2015 onwards, increased flows from Culcairn.

Congestion uplift allocation unfairly penalises small market participants and new entrants

The congestion uplift allocation methodology imposes relatively greater costs on smaller market participants and new entrants compared to larger participants. In the current environment where we are anticipating an east coast gas supply shortfall and domestic buyers have reported experiencing issues with accessing gas supply[7], it can also be very difficult for a new entrant with a small starting position to secure the right combination of physical supply and AMDQ Credits/AMDQ to give effect to a congestion uplift hedge. Hence smaller participants and new entrants are more likely to be exposed to such costs relative to larger and more established participants. Further, we note that it is not economically viable for new entrants/small players to invest in LNG storage capacity. Even if they were to do so, having LNG storage capacity does not provide a completely reliable hedge against uplift costs (through receipt of ancillary payments) as the scheduling of a participant's LNG offer will depend on where the offer sits in the bid stack at the time.

In addition, Tariff D sites in Victoria that do not have any AMDQ (i.e. any new site established after 1998), may be adversely impacted under the current market design. Retailers may be less willing to service sites without AMDQ compared to those with AMDQ, or may charge higher prices to customers without AMDQ. Further, the curtailment protection provided by AMDQ given to sites simply because they were there first (i.e. in existence prior to 1998 when the original Longford AMDQ was allocated) also seems inequitable. The AMDQ regime is clearly creating

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[7] A range of industry studies predict a shortfall of gas supply for the domestic market, due to the significant amount of gas being diverted to Queensland for export combined with constraints in developing new gas supply sources e.g. in NSW. AEMO Gas Market Statement of Opportunities 2013, the Victorian Gas Market Taskforce Final Report and Recommendations (page 16) all indicate the possibility of gas supply shortfalls.

perverse outcomes in today's market and is in need of review. Changes should be made to ensure that the market design is giving effect to rational and equitable outcomes.

Magnitude of risk exposures

Uplift risk is a recognised key risk associated with the DWGM, with $48.5m incurred in 2007, $494k in 2008, $14.6k in 2009, $16k in 2013 and zero in 2010, 2011, 2012 and 2014.[8] Although uplift costs have been minimal in recent years, changes in market dynamics, introduction of an LNG export industry, potential domestic gas shortfalls, increased export flows out of Victoria and changes in the AEMO pricing scheduling process[9], are all factors likely to give rise to an increased need for out of merit order gas, ancillary payments and hence higher uplift costs. Given the size of the potential exposures it is extremely important to ensure that costs are being allocated in a fair manner. Failure to correct this inequity will discourage new entrants and erode competition.

AEMC assessment framework

In the context of the AEMC assessment criteria, the issues discussed above are contributing to *Outcome 1 - Imposing inefficient costs, Outcome 2 - Exposing parties to risks that are not allocated efficiently* and *Outcome 4 - Acting as a barrier to entry*.

Recommendation

In the near term, and until such time when more significant changes to the market design are made that would materially modify or overhaul the ancillary payment/uplift charges regime, a rule change should be made to enable all uplift costs to be recovered through the existing surprise and common uplift mechanisms. Currently, positive surprise uplift is allocated to short deviations in the immediately prior scheduling interval and revisions to operating schedules that increase a participant's net buy (or short) position in the current schedule. Common uplift is smeared in accordance with withdrawals. We think that uplift costs are more appropriately allocated via these methods (in the absence of more material changes to the ancillary payments/uplift cost regime that may emerge from the AEMC review in the longer term). The concept of congestion uplift should be discarded.

We expect that parties who support the current regime will argue that the current AMDQ regime helps to drive an efficient level of pipeline utilisation and investment, and diminishing the value of AMDQ/AMDQ Credits would reduce investment incentives. We disagree. It is inefficient for participants to be driven to fund future pipeline expansions simply to secure AMDQ Credits to minimize exposure to uplift costs that are a result of surprise or other events that may occur regardless of whether pipeline investment is undertaken. We also note that AMDQ and AMDQ Credits currently provide other benefits to their holders, such as tie breaking rights.[10]

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[8] AER website, Industry Information, Industry Statistics, Wholesale Statistics, Positive Ancillary Payment Events data.
[9] In 2014, AEMO reported that it had identified an issue with the scheduling process, in that it had been applying certain constraints in the Pricing Schedule, when under the rules, it is only supposed to apply such constraints in the Operational Schedule. AEMO have since proposed changes to procedures to enable it to only apply such constraints in the Operational Schedule. The effect of this will be a greater likelihood of out of merit order gas being required and hence ancillary payment sand uplift costs. Refer to AEMO publication, "*IIR 15-002 Update to Gas Scheduling Procedures for the Application of Constraints to the Pricing Schedule*".
[10] Although we question whether this benefit actually helps to promote pipeline investment when the benefit is not a firm right to inject or withdraw (a non AMDQ/AMDQ CC holder can be prioritized over an AMDQ/AMDQ CC holder on the basis of bid price).

In the longer term, the entire uplift costs/AMDQ regime should be reviewed in the context of determining an appropriate mechanism that would provide effective incentives for efficient pipeline investment.

A2. Inadequate investment signals and limitations of existing capacity instruments

ERM Power shares the view that the lack of firm transportation rights in the Declared Transmission System reduces the incentives for market-led investment in pipeline capacity expansions (contributing to AEMC assessment framework *Outcome 3 -Impeding efficient investment decisions*). This can result in the market's needs not being optimally met, with system expansions failing to occur in a timely manner (given that investments need to go through the regulatory approval cycle) or not occurring at all. We also observe that the current regime does not allow the asset owner to optimise investment decisions, nor does it enable the asset owner to optimise daily operations.

ERM Power recommends that the review should explore ways in which market led investment in pipeline expansions could be encouraged and investment made more efficient. That said, we emphasize that we do not consider the current regime of uplift charges/AMDQ to be providing an appropriate or effective pricing signal to encourage such investment (refer to our comments in section 1) and are certainly not suggesting that the longer term solution should be one that builds on the current uplift/AMDQ mechanism.

An approach that would be worth exploring is to allow market participants to contract for firm transportation rights in respect of all new expansions. Certainty of price and firmness of access to capacity will provide market participants with a stronger incentive to invest.

If a system of tradeable transmission rights were to be introduced, there should be careful consideration given to ensuring the design is of minimal complexity, appropriately structured to provide priority or firmness in transport, and does not endow its holders with unrelated or ad-hoc benefits that cause costs to be shifted to other parties (similar to the current regime of uplift charges/AMDQ).

A3. Unhedgeable risks and limitations of financial hedging products

As part of the broader review of the DWGM, there would be value in exploring the merits of moving away from the current unconstrained pricing and ancillary payment/uplift cost regime, and considering alternative models that would better help facilitate the COAG Energy Council's vision for the gas market.

Under the current market arrangements, uplift cost exposure is a risk that is largely unhedgeable. In terms of the AEMC assessment framework, the current arrangements are resulting in *Outcome 2 - Exposing parties to risks that are not allocated efficiently* and *Outcome 4 - Acting as a barrier to entry.*

We refer to our earlier comments in section A1 regarding the way in which congestion uplift fails to allocate costs to their cause. The remaining cost allocation mechanisms, surprise and common uplift, generally have the effect of smearing the costs across the market (although we note that surprise uplift allocates costs to deviations and revisions to forecasts and schedules). All participants will always have some degree of forecast error and/or will regularly update their schedules, and hence all participants will always have some exposure to uplift costs. Uplift risk is therefore largely unhedgeable.

The only way a participant can attempt to offset the financial impacts of uplift costs, is by offering LNG into the market (i.e. supplying the out of merit order gas and earning ancillary payments). However LNG is a highly expensive solution. It is also ineffective as a hedge against uplift charges, given that whether a participant is scheduled to inject LNG depends on where it is positioned in the bid stack at the time. In this regard the current arrangements are also contributing to the AEMC assessment framework *Outcome 1– Imposing inefficient costs*, where such costs will eventually be passed on to gas consumers.

Currently the ancillary payment/uplift charge regime also inhibits the development of a financial derivative market in Victoria, as simple financial products such as a swap, are ineffective in providing a hedge against key market risk. In our view, this is likely to be one of the main reasons why the Victoria gas futures listed by the ASX in 2009 have rarely been traded. If instead all (or the majority) of costs were reflected in the spot price, the attractiveness of financial hedging products would be likely to increase.

A4. Complexity of market arrangements

In comparison with the STTM and the Gas Supply Hub, the DWGM contains some extremely complex elements, particularly relating to the settlement processes. Such complexity gives rise to *Outcome 1 - Imposing inefficient costs* and *Outcome 4 - Acting as a barrier to entry*. Complexity also reduces information transparency and participants' ability to manage their trading positions and to understand, anticipate and manage market outcomes, contributing to *Outcome 5* which relates to market information inadequacies.

The complexity of this market was acknowledged in stakeholder concerns raised in the K. Lowe Consulting report commissioned by the AEMC.[11] We believe that the market design could be simplified considerably in certain areas, one in particular being the ancillary payments and uplift charges calculations (which are explained and implemented via four AEMO procedural documents totalling 144 pages and consisting of complex algorithms[12]). The complexity makes it very difficult for a market participant, in particular a new entrant without prior experience, to quantify its settlement and risk exposures, and can discourage entry of new market participants.

A5. Victorian Gas Market Price cap is excessive

We recommend that the maximum market price in the DWGM should be reviewed (as well as the STTM Maximum Market Price), with specific consideration to bringing the price cap down to a lower level such as $100/GJ to $200/GJ so as to reduce retailer risk.

The higher the value of the market price cap, the higher will be the risk faced by retailers, in particular new entrant retailers and any other small participants, who in contrast to the more established and larger retailers, may not have access to a diverse gas supply portfolio (hence more exposed to risks like producer FM) and who may be more likely to rely on the spot market to meet some of their load. Also, the higher the price cap and the risk, the higher will be the risk

[11] K Lowe Consulting, 2013, *Gas market scoping study: a report to the AEMC*, section 10.3.1, pg. 95, and section 11.4.1, pg. 109.

[12] The four procedures mentioned include a 40 page "*Uplift Payment - Functional Design v 9.0",* 32 page "*Wholesale Market Uplift Payment Procedures*", 46 page" *Ancillary Payment Functional design*", and a 26 page "*Wholesale Market Ancillary Payment Procedures*", available on the AEMO website.

premium added to customer prices in the long run, an outcome inconsistent with the National Gas Objective.

While it could be argued that the Cumulative Price Threshold (CPT) and the Administered Price Cap (APC) should assist to reduce retailer risk, past experiences (such as the 22 November 2008 incident in Victoria where the price reached $800/GJ, CPT did not apply and APC was not triggered) have shown that the maximum market price setting can have significant impacts and give rise to wealth transfers with no market benefit. While a larger or more established participant may be able to wear the costs of such an event, such an event is likely to result in permanent financial damage to a smaller participant or new entrant.

In Victoria, not only does the price cap impact the imbalance and deviation prices, but also uplift cost exposures. As noted by the AEMC in its discussion paper, one of the factors guiding the original rationale for adopting the DWGM was to facilitate retail contestability and the entry of new players by enabling them to source their initial gas supplies from the spot market.[13] For this objective to be achieved, risks need to be lowered to a manageable level. Although the likelihood of prices reaching the price cap may be low based on history, it is nevertheless a real risk that needs to be accounted for.

The magnitude of the risk can deter the entry of new participants. For example, consider a small retailer with annual load 1 PJ per year (less than 5% market share)[14] who happens to have an unhedged load of 5 TJ on a day on which the 6am price hits $800/GJ. Ignoring deviation costs, this retailer would incur a one day cost of $4m, which for a small retailer would be likely to far exceed its annual expected profit. Utilising the average gross margins as reported by incumbent retailers[15], being roughly $4.60/GJ for residential and SME customers and roughly $0.8/GJ for business customers, a retailer with annual sales as described in our example, would expect to earn an approximate annual gross margin of $4.6m if it served residential and SME customers or $0.8m if it served business customers. A maximum market price event at 6am, occurring on one day, would result in significant losses for the entire year in both cases especially after retail operating costs are considered, and certainly wipe out profits completely if more than one event occurred in a year. We note that for a new entrant retailer, net retail margins are likely to be lower given a smaller customer base over which to spread fixed costs. In terms of the AEMC assessment framework, the current DWGM price cap contributes to *Outcome 1 – Imposing inefficient costs*, and *Outcome 4 – Acting as a barrier to entry/deterring competition*.

B. WALLUMBILLA GAS SUPPLY TRADING HUB

ERM Power is currently a trading participant at the Wallumbilla Gas Supply Hub and has been a member of the Gas Supply Hub Reference Group since its establishment in February 2012. Our view is that the Wallumbilla Gas Supply Hub does provide value to participants in assisting with

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[13] AEMC Public Forum discussion paper, pg.6.

[14] Based on forecast annual consumption of 211.5 PJ for 2015, as reported in AEMO's National Gas Forecasting Report 2014.

[15] Average gross margins based on total sales and total gross margins reported by AGL ("*FY15 Interim Results Half Year ended 31 December 2014*", 11/02/15) and Origin Energy ("*2015 Half Year results announcement*" 19/2/15) for the six months ending 31/12/14. For the consumer market, AGL reported 34.6 PJ of sales and $160m gross margin, equating to an average gross margin of $4.6/GJ. For business customers, AGL reported sales of 44.1 PJ and gross margin of $34m, equating to an average gross margin of $0.78/GJ. Origin Energy reported a gross profit of $3.1/GJ across its customer base.

the management of the short term trading position, although there are some enhancements that could be made to encourage increased liquidity. We provide comments on two issues raised by the AEMC on the Gas Supply Hub and share our views on some ways in which liquidity could be enhanced.

B1. Moomba Gas Supply Hub

We support the development of a Moomba Gas Supply Hub. We disagree with the claim put forward by some parties that a Hub at Moomba should not be established because it will reduce liquidity of the Wallumbilla Gas Supply Hub. While it is true that some participants who are able to trade at both locations may elect to trade at Moomba if the two Hubs coexisted (and thereby reduce liquidity at Wallumbilla), we do not consider the possibility of reduced liquidity at Wallumbilla to outweigh the benefits of establishing a Moomba trading exchange. A Moomba Gas Supply Hub will benefit an entirely different set of market participants, including those shippers operating on the Moomba to Adelaide Pipeline and the Moomba to Sydney Pipeline (participants in the Sydney and Adelaide markets). Some of these participants may not necessarily operate at Wallumbilla. A Moomba Gas Supply Hub may also be of value to shippers who utilise the Culcairn interconnect for deliveries into Victoria, and participants who are operating in non STTM areas of NSW and ACT via the Moomba to Sydney Pipeline. Subject to establishment costs being low and the absence of any increase in fees imposed on existing participants, we think a Moomba trading exchange would bring value and should proceed.[16]

B2. Single trading zone design

We note that AEMO has been tasked by COAG to consider the benefits of moving the existing Wallumbilla Gas Supply Hub design to a single trading zone/single product model. We have some concerns regarding the cost-benefit proposition as explained below.

The majority of products traded on the Gas Supply Hub to date have been at the RBP trading location, followed by the SWQP trading location and no products traded at the QGP trading location. Shippers need to have contractual rights to sell or buy at a particular trading location. A shipper who does not have contractual access to a particular trading location, but who desires access, is able to secure redirection services with the transmission pipeline operator to obtain such access. We are unaware of any issues with securing such access (although capacity limitations would need to be confirmed with the pipeline operator). If a shipper chooses to secure such additional services, there must be a clear commercial benefit from doing so, otherwise it would not seek to secure those services which come at a fee.

It is unclear whether trades will actually increase under a single product/trading zone model if it is the case that participants can already currently trade at any of the trading locations by securing the relevant services from the pipeline operator.

We would be concerned if a single trading zone model effectively forces participants to pay for a suite of mandatory additional services that they would not normally have purchased - this will result in cost inefficiencies and in the context of the AEMC assessment framework, lead to *Outcome 1 - Imposing inefficient or unnecessary costs*. Increased participation costs could deter participants from entering or trading in the market, leading to *Outcome 4 – Acting as a barrier to*

[16] We understand that costs are expected to be low, as the Moomba Hub would leverage off the Wallumbilla Gas Supply Hub design and trading infrastructure.

entry. ERM Power's view is that that there needs to be a significantly compelling case for net benefits, to warrant a move to a single product/trading zone model.

B3. Minimum parcel size

Currently the minimum parcel size is 1 TJ. This minimum parcel size will not be an issue for larger players (e.g. LNG producers) but is likely to be too large for smaller participants and in particular new entrant retailers who are in the infant stage of building up their retail customer base. The minimum parcel size constraint should be removed (or at least reduced) to minimise barriers to entry (relevant to *Outcome 4* of the AEMC assessment framework).

In addition to benefiting smaller participants, removing the minimum parcel size will also increase the utility of the Gas Supply Hub to larger participants who may be willing to trade small volumes on the exchange if able to do so and generally facilitate a more efficient balancing of over overs and unders.

We note that the Gas Supply Hub currently allows a participant to select "All or None" as a criteria when placing a bid or offer on the exchange (meaning that the parcel in its entirety has to be transacted). We are not proposing that this feature be changed.

Removing the minimum parcel size constraint would attract additional players to the Gas Supply Hub, including retailers, bringing benefits of competition to gas consumers in Queensland. We note that the STTM has no minimum bid/offer restriction, and neither does the DWGM.

B4. Gas Supply Hub fees

While ERM Power supports the Gas Supply Hub, our view is that the current fixed fees for a trading participant are excessive and should be reduced. Currently the fees are $14, 500 per annum for a single user account, with an incremental $5,500 per annum for each additional user account (note that these are in addition to the variable costs of $0.03/GJ for a daily product and $0.02/GJ for a weekly product). A single user account means that the trading application can be opened up by a single user on a single screen at a time, and not shared across multiple users. For $14,500 per annum, we would expect that an organisation should be able to create as many user accounts as required for its trading team. In particular where trading teams are located in different regions or when trading personnel are travelling, traders need to be able to access the trading application without restrictions. In the DWGM and STTM, we note that there are no limits on the number of accounts that can be created for access to MIBB, MIS, Webexchanger or STTM Webexchanger (the information and bidding portals).

Relaxing the constraint on the number of user accounts would reduce participant costs, assist participants to better manage their trading positions and encourage greater use of the Gas Supply Hub and hence promote increased trading activity. In the context of the AEMC assessment framework, *Outcome 1 (Imposing inefficient costs), Outcome 4 (acting as a barrier to entry)* and *Outcome 5 (information provision inadequacies)* are relevant.

C. CAPACITY TRADING

ERM Power notes its support for the various initiatives arising from the COAG Energy Council's Regulation Impact Statement (RIS) on Gas Transmission Pipeline Capacity Trading, including improvements to the Bulletin Board, the introduction of a capacity listing service, development of standardised contracts, and the provision of additional information on pipeline utilisation and capacity trading on the Bulletin Board.[17] We also view the operational transfer capacity trading services and in-pipe trading mechanisms introduced by the transmission pipeline operators as being positive developments.

While we welcome the above initiatives, it not evident to us as to whether they have had any effect of enhancing the level of capacity trading. In this regard it may be worthwhile to revisit the concept of a voluntary capacity trading platform (Option 3 in the RIS) and also the earlier work undertaken by the Brattle Group in 2013, commissioned by AEMO, "International experience in pipeline capacity trading". In parallel with the COAG Energy Council initiatives already underway, there could be merit in further investigating how overseas trading models might be applied in the east coast Australian gas market context. This might include consideration of policies that require spare capacity (subject to certain definition criteria) to be released for sale with the sale proceeds going to the capacity holder so they are not adversely impacted. Of course, the case for introducing any new trading regime would need to be supported by a cost benefit analysis and integration and/or compatibility with the existing commodity trading exchange at Wallumbilla (and in the future Moomba) would also be a consideration.

ERM Power's view is that a voluntary capacity trading platform would have the potential to reduce transaction costs, provide incentives for both pipeline operators and shippers to trade unutilised capacity, encourage short term trading and help market participants manage their trading position.

In the context of the AEMC assessment framework, a reduction in transaction costs would negate *Outcome 1 (Imposing inefficient costs)*, enhanced access to pipeline capacity and improved ability to manage short term trading positions would help negate *Outcome 4 (barriers to entry)* and greater transparency of pipeline capacity availability would negate *Outcome 5 (which relates to information inadequacy)*.

D. ACCESS TO RELEVANT MARKET DATA AND NEED FOR GREATER TRANSPARENCY OF SUPPLY/DEMAND INFORMATION RELATED TO LNG FACILITIES

Access to relevant and timely information about the factors influencing supply, demand and price plays an important role in helping participants make informed trading and investment decisions and hence manage their commercial positions. In this regard we acknowledge the value of the data published by AEMO in relation to the DWGM and STTM, as well as the data available on the National Gas Bulletin Board (GBB), which includes important information such as pipeline flows, production facility output data and capacity outlook information. However a clear deficiency is the lack of publicly available information relating to the LNG industry, despite the significant flows of gas arising from the LNG industry and its ability to impact domestic energy market outcomes. The GBB currently captures data relating to pipelines and facilities that connect to, or are captured in, a set of defined Production Zones and Demand Zones. The absence of a Gladstone (LNG) demand zone means that LNG pipelines are excluded. This results in an incomplete picture of the market. In the context of the AEMC assessment criteria, *Outcome 5 – timely and accurate*

[17] Standing Council on Energy and Resources, *Regulation Impact Statement, Gas Transmission Pipeline Capacity Trading, Decision Paper*, 2 December 2013.

information required by the market, is highly relevant to this issue. We note that *Outcomes 1 to 4* are also consequences of the absence of relevant market information.

Once the LNG plants come into operation total eastern Australian gas demand is expected to rise from 697 PJ per annum in 2012 to 1,395 PJ per annum in 2015 and 2,386 PJ per annum in 2020, with domestic gas demand expected to flatten or slightly decline over the same period.[18] The sheer size of the LNG industry and the interconnected nature of the east coast energy market mean that the LNG industry will have a significant impact on the domestic gas, electricity and related financial markets. Fundamental market information relating to the LNG industry should be made publicly available, similar to domestic gas market and NEM data that is currently published.

The publication of LNG information via the GBB would be consistent with the objectives of the GBB under the National Gas Rules (Rule 142), which are to -

> *(a) facilitate trade in natural gas and markets for natural gas services through the provision of system and market information which is readily available to all interested parties, including the general public; and*
>
> *(b) assist in emergency management through the provision of system and market information.*

The following are the potential consequences of not having LNG related information being made publicly available.

- **Increased trading/financial risk imposed on non-LNG market participants** – An incomplete picture of the factors that may impact supply/demand and price will impair participants' ability to make informed and timely operational and commercial decisions.
- **System security risks** – Supply and demand factors impacting the LNG market will inevitably impact the domestic gas market, given the size of LNG anticipated volumes and the physical interconnectedness of the gas market. If non-LNG proponents in the domestic gas market have inadequate information about such supply/demand factors they will be inhibited in their ability to anticipate potential events and plan a suitable response. For example, if an LNG production facility suffers an outage and volumes of gas are diverted away from the domestic market to support the shortfall, this information would be critical to other participants' trading decisions. Such a scenario could result in system security issues and curtailment.
- **Adverse competition impacts of information asymmetry** – LNG related information on supply/demand/capacity will have an impact on prices across the gas and electricity markets, as well as the financial derivatives market. All such information that has the potential to impact price should be disclosed. Without such transparency the LNG proponents will have inside information in the financial and physical (STTM, GSH, bilateral contract market etc.) markets in which they are also trading, and non LNG proponents will be at a competitive disadvantage. We also note that the ASX is currently developing financial products (futures), to be launched at the start of April 2015, structured on prices at the Wallumbilla Gas Supply Hub (in which the LNG proponents are key trading participants). For the wider market (including financial market participants) to have confidence in trading these products, the

[18] *Eastern Australian Domestic Gas Market Study,* Department of Industry & BREE, page 8

market needs to understand the supply/demand outlook and factors that may influence price and have confidence in that data.

- **Asymmetrical reporting requirements** – if one part of the market (existing GBB facilities) is required to report, so should LNG facilities. It would be inequitable for LNG participants have information about existing GBB facilities, where reciprocal information is not available.
- **Barriers to entry, adverse impacts on competition and increased costs to domestic gas consumers** – The risks described above could discourage the entry of new participants and adversely impact liquidity and competition. The inefficiencies arising from inadequate information availability could lead to increased costs which will ultimately be borne by domestic gas consumers.

We strongly recommend that the GBB rules be amended to reflect the establishment of an LNG/Gladstone demand zone, thereby capturing LNG pipeline flows (historical and forecast) as well as capacity outlooks/outage information related to LNG facilities.