Energy Supply Association of Australia www.esaa.com.au

ABN 98 052 416 083

Level 14
50 Market St
Melbourne

GPO Box 1823
Melbourne
Victoria 3001

P +61 3 9205 3100
E info@esaa.com.au

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Australian Competition and Consumer Commission
Level 20, 175 Pitt Street
Sydney NSW 2000

Lodged (by email): gas.inquiry@accc.gov.au

East Coast Gas Inquiry – Issues Paper

The Energy Supply Association of Australia (esaa) welcomes the opportunity to make a submission to the Australian Competition and Consumer Commission's (ACCC) East Coast Gas Inquiry Issues 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 has undergone significant transformation over the past 20 years. Bilateral contracting has facilitated investment in production/transportation infrastructure and connected regional demand centres with multiple supply points; competition in retail markets has emerged; and facilitated trading markets have been developed to provide a transparent and market based mechanism for managing daily imbalances.

While it is expected the east coast gas market will continue to evolve over time, the market is currently in a state of transition. Production costs are rising, political uncertainty is hampering onshore gas development in a number of regions and most notably, the liquefied natural gas industry (LNG) is driving a step change in demand.

As conventional gas resources diminish, the LNG export industry will be a key driver of continued resource development in Australia, providing a level of demand and capital that is sufficient to underpin the development of significant and higher-priced coal seam gas (CSG) and other unconventional gas resources. Despite the obvious economic benefits this creates, linkages to LNG export markets do change the competitive environment relative to business as usual, exposing the domestic market to the influence of world prices and a competing source of demand that will far exceed domestic demand.

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.[1] This compares with total east coast domestic demand of around 570 PJ.[2]

[1] Australian Energy Market Operator, *National Gas Forecasting Report*, December 2014.
[2] Ibid.

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 Association has provided more contextual information describing the changes currently underway in the east coast gas market as well as more specific material relating to some of the broader issues being investigated by ACCC in Attachment 1.

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

Kieran Donoghue
General Manager, Policy

Attachment 1

Part 1: Changes affecting the domestic gas industry

The LNG export industry is changing gas market dynamics

For decades the only market for gas produced in eastern Australia has been the domestic one. This has resulted in long-term contracts at prices significantly below world prices. These long-term contracts ensured large projects in places like the Cooper Basin and Bass Strait could be developed, allowing Australian customers to enjoy some of the lowest gas prices in the world. The opening of the east coast to export markets is challenging this market dynamic. Beyond simply introducing a competing source of demand that will far exceed domestic demand, it also changes the competitive environment.

From a resource development and diversity of supply perspective, it is important to note that LNG exports and domestic supply are not mutually exclusive. In order to maximise the profitability of a project, there is an economic rationale for LNG proponents to divert a proportion of capacity to the domestic market where there is demand. Even under circumstances where the domestic gas prices may be lower, since the LNG revenues forgone are towards the end of the project lifespan, on a discounted basis they may be worth less than domestic revenues that can potentially be achieved earlier.

Companies that currently have LNG interests but also have an historical presence in the domestic gas supply industry will likely want to maintain their established position in the domestic market for commercial reasons. Small fields geographically distant from the current set of proposed LNG projects may be developed primarily or exclusively for the purpose of domestic supply.

With this in mind, the development of LNG export capacity does not mean gas producers will simply forgo the domestic market over the longer term. But the newly created link to the LNG export market is likely to change the contracting environment in two key ways:

- Opening the east coast to export markets also opens it to world prices. This means gas prices have the potential to rise to international levels over time as producers supplying the domestic gas market seek to lock in returns at least as high as could be achieved under LNG export contracts. There may also be a push for oil-indexation in preference to other indexes (e.g. east coast electricity prices), given this is the dominant price formation mechanism in the Asia Pacific Region.

- Contract terms (including length of coverage) may vary from previous market norms as competition for supply increases.

These factors will likely lead to domestic gas buyers assuming more risk, both in terms of the overall gas price and volume of supply. In this respect, the period straddling LNG start-up is likely to be particularly challenging for domestic gas buyers given they will be required to take a position on the future price path for domestic gas while the market is still in a state of transition. In the absence of deep and liquid secondary markets, buyers will need to be flexible in their approach to managing this risk. Recent investments by some energy companies and large energy users may also point to the benefits of vertical integration in this regard.

Tight supply and rising wholesale gas prices will have an impact on domestic demand

It is anticipated there is sufficient gas to support domestic and export demand for at least the next 20 years based on current reserves and resource estimates. But this assessment is predicated on continued resource development and modest domestic demand growth relative to historic levels.

Tight supply and rising wholesale gas prices are expected to have an impact on domestic gas demand on the east coast. According to the Australian Energy Market Operator's (AEMO) latest forecasts, total demand will decline at a rate of 5.2 per cent per annum over the 2014-19 period.[3] This fall is largely attributable to a decline in demand for gas-fired electricity generation, which is expected to decrease by an average 16.8 per cent annually over the period.[4] In comparison, demand for the large industrial market segment is forecast to decline at an average annual rate of 3.4 per cent, while the mass market (residential and commercial) is expected to grow by 1.1 per cent.[5]

The decline in demand from the electricity generation sector reflects a number of factors. Demand for electricity is low, government policy continues to push renewable energy capacity into an already oversupplied market and the lower emissions intensity of gas generation compared to the dominant fuel, coal, gets no recognition in the market. Coupled with an increase in the wholesale price of gas and gas-fired electricity generation is pushed down the merit order, largely confined to playing a balancing role in the market.

This profile of rising costs coupled with a potential reduction in domestic demand over the medium term may pose some challenges from an asset utilisation perspective, the ramifications of which would extend to all users. To the extent there is a decline in mass market consumption driven by a shift away from gas-fuelled appliances, a reduction in distribution network throughput could lead to higher network charges as network businesses seek to recover costs from fewer units, thus driving prices higher and gas usage lower.

New South Wales is particularly exposed in this respect, given the low penetration of natural gas at the mass market level relative to Victoria and the Australian Capital Territory.[6] But it is important to note that the wholesale price of gas forms only one component of the bill paid by mass market consumers. The Australian Energy Regulator's 2015-20 final determination for the Jemena Gas Network in NSW is particularly relevant in this regard, given it is expected to deliver annual bill savings in the order of $96 for the average residential consumer in 2015-16.

Joint marketing arrangements

The esaa has consistently advocated for the removal of the joint marketing authority currently granted to the Gorgon and North West Shelf Joint Ventures when the applications come up for renewal in 2015. In the Association's view, joint marketing is an impediment to upstream competition in the context of the heavily concentrated Western Australian domestic gas market.

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[3] Australian Energy Market Operator, *National Gas Forecasting Report*, December 2014.

[4] Ibid.

[5] Ibid.

[6] While households in NSW connect to electricity as a matter of course, only around 62 per cent of NSW households have gas infrastructure available and of those, some 70 per cent are connected.

Given different market characteristics on the east coast, including greater diversity of supply, the extent to which separate marketing would lead to lower gas prices and/or improved terms and conditions for gas supply agreements in that region is not clear. To guide the ACCC's consideration in this regard, the Association is supportive of pursuing the elimination of joint marketing arrangements for upstream gas supply where they have the effect of substantially lessening upstream competition and the domestic gas market has matured to a level that enables proponents to adequately manage the risks associated with separate marketing.

Part 2: Access to new gas reserves

Resource development continues to be constrained by political intervention

The development of unconventional gas reserves and resources has been constrained on the east coast to date, principally as a result of political uncertainty and overly restrictive planning laws and regulatory frameworks. Such an environment has severe implications for the timeliness and diversity of supply, as it creates barriers and risks to investment at a time when continued resource development is essential. NSW is at the forefront of this issue and serves as an example of the problems that could emerge across the broader east coast market unless appropriate policy settings are in place for the exploration, production and supply of gas.

At its core, Australia's environmental planning and regulatory framework for resource development has numerous overlapping, excessive and inconsistent requirements that cause unnecessary project delays and costs. According to research conducted by the Australian Petroleum Production and Exploration Association, duplicative state and federal regulations may be holding back projects worth around $200 billion without any environmental benefit.[7] The Productivity Commission reiterated these concerns, highlighting the overlap and duplication of similar regulatory processes as "one obvious source of unnecessary burden for proponents of major projects".[8]

Despite work under way at a national level to reduce regulatory burden (e.g. implementing a 'one-stop-shop' for environmental approvals), for a number of regions it is difficult to see real progress. The NSW Government's recent declaration that it is committed to growing indigenous gas supply is a welcome development in this regard. But overcoming the current suite of issues will require governments at all levels to establish environmental and planning processes that appropriately balance the social, environmental and economic costs/benefits of resource development and avoid unnecessary duplication.

Regulations should be based on sound scientific principles and assessment, maintain high environmental safety standards and provide regulatory certainty and consistency across all jurisdictions. Above all, they should provide a stable and predictable foundation for the development of gas resources. Achieving this will allow the east coast gas market to efficiently adjust to the new paradigm.

Administration/management of petroleum titles could be improved

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[7] The Australian Petroleum Production and Exploration Association, *Cutting green tape: streamlining major oil and gas project environmental approvals processes in Australia*, February 2013.

[8] The Productivity Commission, *Major Project Development Assessment Processes – Research Report*, November 2013.

The Commonwealth Government previously outlined changes to the management of oil and gas retention leases with a view to delivering greater scrutiny of applications. These included:

- Verifying that companies seeking to retain a lease over oil or gas fields have a legitimate need to secure gas for long-lived production projects and are not simply seeking to obtain a competitive commercial advantage by their retention.

- Should a field become commercial, requiring the company holding the retention lease to apply immediately to the Minister for a production licence to bring the field online. Alternatively, at the end of the retention lease period, the lease should be offered on a tender basis for a production licence.

Arguably the most essential component of the retention lease system, limited transparency with respect to the way in which commerciality is assessed has raised some concerns about the appropriateness of retention lease policy arrangements more broadly. In particular, that a potentially narrow assessment of commerciality could potentially subdue obligations on producers to bring commercially viable gas resources to production.

Resource development is a high risk and capital intensive activity and there are multiple commercial considerations that govern the overall timing and scale of project development. As such, it is important to provide resource businesses with the scope to deliver efficient investment across their broader portfolio. But given the need to promote continued resource development, the Association is supportive of actions to provide greater clarity and transparency around the application of retention leases.

Part 3: Information availability and trading liquidity

Any improvements to information provision should be appropriately targeted

Improving the market's ability to form expectations about gas supply is in the interest of all market participants. To the extent there is additional information from upstream projects that could be voluntarily reported to the market, this may be useful. A key first step would be to determine the type of information that could be reasonably provided under current reporting arrangements. Careful consideration would obviously need to be given to the risks of revealing commercially sensitive information.

If mandatory data/information requirements are contemplated, the compliance costs associated with such provisions should be taken into account. While it would be difficult to conduct a cost-benefit analysis per se, any information requested would need to deliver value to the market more broadly.

It would also be unreasonable to impose requirements on CSG and LNG proponents and not the upstream sector more broadly. Improving market information about gas supply from CSG projects will not resolve market tightness in the near term and should not therefore, be used as justification by policy makers for imposing specific requirements on those businesses alone.

Facilitated markets provide limited flexibility and are generally seen to impose risk

Given the size of the LNG export volumes that are anticipated on the east coast, it is clear continued resource development will be 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.

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. They also play an important role in enabling new entry to the gas market, providing participants with access to gas in the initial phase of market entry and allowing them to develop the experience and understanding of demand requirements before committing to long-term bilateral contracts for supply and transportation. In this regard, the Declared Wholesale Gas Market (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 the complexities and pricing risks associated with trading in these markets may diminish their overall value. The facilitated markets are mandatory and where a participant takes a position that is not covered contractually, they become exposed to potentially high prices in the event of market disruptions that cannot be effectively hedged. As a result, market participants generally seek to closely match their own injections and withdrawals to minimise exposure and manage their risk with longer-term bilateral contracts. Differences between the facilitated markets also represent an added level of complexity for businesses operating across different jurisdictions.

The limited size of the east coast gas market may provide a barrier to increasing trading and liquidity on the facilitated markets and long term agreements for gas supply and (outside the DWGM) transportation remain essential for establishing a sustainable position in the east coast gas market. But reducing transaction costs and minimising the risks associated with participation could support market development and ensure the facilitated markets deliver value to market participants in the future. This may potentially pave the way for the establishment of financial risk management products and ultimately a reliable price index. The ability to obtain a forward price for gas that is visible and tradeable is an important feature of liquid and transparent gas markets globally.

The Australian Energy Market Commission (AEMC) is currently investigating these issues as part of its East Coast Wholesale Gas Market and Pipeline Frameworks Review. As noted in the Association's response to the Stage 1 Draft Report, the Association is supportive of the AEMC examining the appropriateness of the facilitated market designs. In particular:

- considering whether the original objectives of the facilitated markets remain relevant respectively and whether those objectives are being efficiently achieved;
- examining the case for redesigning the STTM design with a view to simplifying the market design and reducing costs for market participants;
- reconsidering the design of the DWGM to establish whether energy prices can be separated from balancing and uplift charges; and
- investigating how the Wallumbilla GSH can best interact with other facilitated markets in the future, with a focus on participation and liquidity.

Given the interconnected nature of the east coast gas market, the Association believes the above analysis could be incorporated into a long term strategy for the location and form (i.e.

voluntary/non-voluntary) of facilitated gas markets. This information would be particularly relevant given work currently being undertaken by AEMO as it develops the conceptual design of a potential Gas Supply Hub (GSH) at Moomba. But more broadly, it will assist with providing a more holistic and strategic view of changes required in the east coast gas market and how any additional hubs/facilitated markets fit within that framework.

Part 4: Gas transportation

Regulation of pipeline infrastructure

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.

Long-term bilateral contracts are likely to remain a prominent feature of the market given the capital intensive nature of gas production/transportation and commercial and regulatory signals driving investment remain appropriate. But there are potential efficiencies in utilisation to be gained through mechanisms like capacity trading (addressed in more detail below). Further, persistent policy uncertainty in the exploration/production sector has the potential to impede the timeliness and efficiency of infrastructure investment and supply. As discussed, it is difficult for businesses to commit finances when the rules/regulations governing access to supply are in a constant state of flux.

With regard to the suitability of different carriage models for pipeline regulation, there are strengths and weaknesses to both the market carriage and contract carriage models. Despite these differences, the current hybrid approach where different models apply to different assets appears to have met the particular demands of the market and it is not clear there is an immediate issue to be resolved.

The no-coverage option for transmission pipelines remains an important feature of the current regulatory framework

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 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. The absence of a requirement to publish standard reference tariffs and associated terms/conditions also reduces transparency and certainty for prospective shippers to some degree. But it should be noted that a number of major non-covered pipelines do publish this information.

Taking the above into consideration, it is not clear 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. While the extent to which pipelines ultimately compete with one another is obviously influenced by the availability of upstream gas resources, 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.

The extent of any impediments to secondary pipeline trading remain unclear

Limited trading of secondary pipeline capacity 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.

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.