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Jemena Limited
ABN 95 052 167 405

Level 16, 567 Collins Street
Melbourne, VIC 3000
PO Box 16182
Melbourne, VIC 3000
T +61 3 9173 7000
F +61 3 9173 7516
www.jemena.com.au

By email: gas@industry.gov.au

Sean Sullivan
Chair
Energy Senior Officials
Department of Industry, Science, Energy and Resources
GPO Box 2013
Canberra ACT 2601

Dear Mr Sullivan

Consultation Paper – Options to advance the east coast gas market

Jemena welcomes the opportunity to make this submission in response to the *Options to advance the east coast gas market: Consultation on the Wallumbilla Gas Supply Hub and pipeline capacity trading framework* consultation paper (**the Paper**).

Jemena has invested significantly in the development of the east coast gas market over the past decade. Our portfolio of assets includes a number of major gas transmission pipelines, including the Queensland Gas Pipeline and Darling Downs Pipeline which connect to the Wallumbilla Gas Supply Hub. We also own the Eastern Gas Pipeline, Northern Gas Pipeline and a number of smaller gas transmission and processing facilities across the east coast, as well as the Jemena Gas Networks which distributes gas to over 1.4 million customers in New South Wales.

The Paper outlines Energy Ministers' priorities of increasing participation and liquidity of trading at the Wallumbilla Gas Supply Hub, supporting the efficient use of infrastructure and driving competition and flexibility in the market. However, we do not consider that these priorities alone provide an appropriate basis to guide a reform roadmap that should aim to deliver market outcomes which are in the long-term interests of gas consumers—particularly given the criticality of efficient investment in gas infrastructure in the context of the National Gas Objective.

While we broadly support the exploration of ways in which the gas market may be more open, transparent and liquid, we consider that the guiding objectives and rationale for undertaking this consultation place too much weight on the achievement of shorter-term market outcomes, such as fostering greater liquidity in trade. For example, the Paper appears to draw aspirational comparisons between trading activity at the Wallumbilla Gas Supply Hub and those of the US Henry Hub, despite significant differences in eastern Australia's market structure, scale and infrastructure density.

This emphasis on short-term outcomes comes at the risk of undermining investment signals and confidence, compromising the future investment in infrastructure which will be necessary to the efficient development of the east coast market over the long-term. Ultimately, it will be investment in developing new gas supply—and in the pipelines required to connect this new supply to market—which will have the most fundamental impact on market development, security of supply and gas prices.

Jemena strongly believes that the roadmap to be considered by Energy Ministers must be primarily guided by the National Gas Objective, and in doing so must carefully consider the impact on investment signals of any proposed regulatory or market changes. Any preliminary issues identified through this process which are deemed to warrant further consideration should be subject to detailed analysis to:

- firstly, establish that a market failure exists (and not necessarily just that a market failure may exist under some circumstances in the future)
- secondly, establish that any regulatory intervention will provide a demonstrable benefit in the long-term interests of gas consumers.

Consistent with this, the roadmap should also adopt a staged approach to any planned future actions by allowing time for any lower cost initiatives that may be implemented in the near term to take effect, and for these effects to be examined in detail and subject to comprehensive consultation before any further work is considered.

The roadmap should also consider interactions with the three other significant national gas regulatory reform packages currently in the process of being implemented or under consideration, and be cognisant of the risks that a lack of regulatory stability and certainty present to all market participants. Providing a regulatory environment which encourages, not dissuades, the development of new gas basins and infrastructure remains critical—particularly in the context of a decarbonising economy where, despite the need for gas to support energy system emissions reduction, financing and achieving public support for critical gas infrastructure is increasingly difficult.

We have provided answers to of the Paper's questions in the attached stakeholder feedback template, and we would welcome the opportunity to further engage with you on the development of the roadmap. Should you have any questions, please contact James Harding, Gas Markets Regulation Manager, at james.harding@jemena.com.au.

Yours sincerely

Ana Dijanosic

Ana Dijanosic
General Manager Regulation

Attachment – Stakeholder feedback template

Attachment A: Options to progress the east coast gas market – Stakeholder feedback template

Submission from Jemena Limited

The template below has been developed to enable stakeholders to provide feedback on the paper Options to advance the east coast gas market, in particular:

- Key issues and barriers to performance, participation and liquidity of the Wallumbilla Gas Supply Hub, and potential policy options
- Key issues and barriers to effectiveness of the pipeline capacity trading framework, and potential policy options
- Broader issues and options which could enable greater liquidity and participation through related enabling frameworks

Officials strongly encourage stakeholders to use this template, so that it can have due regard to the views expressed by stakeholders on each issue. If you wish to provide additional feedback outside the template, wherever possible please reference the relevant question to which your feedback relates.

Chapter 2: Rationale for undertaking consultation

Section 2.4 What are the objectives of Energy Ministers?

No.	Questions	Feedback
1	Do you have any comments about the rationale for undertaking consultation? Does the rationale broadly cover the issues that you face in your interaction with the gas market?	• Jemena broadly supports the Government's aims to establish a more open, transparent and liquid gas trading system. Jemena believes that efficient investment in, and efficient operation and use of, natural gas services will benefit the long-term interests of all participants in the natural gas markets, including infrastructure businesses. This will create benefits for all users with respect to price, quality, safety, reliability, and security of supply of natural gas, consistent with the National Gas Objective (**NGO**).

2	Are there any issues which have not been identified which Energy Ministers should consider in the context of undertaking these workstreams?	**Policy certainty and stability**
		
		• Efficient investment in gas infrastructure remains critical to delivering market outcomes which are in the long-term interests of gas consumers, consistent with the NGO. Market participants place a high value on certainty of price, supply, regulation and demand, and indeed such certainty is critical to driving long-term investment. Investment in additional gas supply and gas infrastructure are the critical enablers necessary to efficiently address the shortfall of gas supply and foster the sustainable development of the east coast gas market over the long-term.
		
		• The regulatory uncertainty associated with recently implemented reforms around the Day Ahead Auction (**DAA**), the Pipeline Capacity Trading (**PCT**) platform, the Part 23 National Gas Rules (**NGR**) information and access framework and, most recently, the proposed pipeline regulation reform package, have tempered our investment appetite for long-lived gas infrastructure unless entirely underwritten by secure long-term contacts. As noted in our October 2021 submission on the pipeline regulation reform package exposure draft,[1] since the introduction of the 2017 gas market reforms, Jemena has only invested in gas transmission projects which have been underwritten by customers, to limit our exposure to cost recovery risk associated with regulatory uncertainty. Additionally, we are concerned about our ability to recover our costs of investing in and operating long-lived gas infrastructure in a climate where the future of the role of gas is uncertain. This is a significant concern for investors at a time when connecting new sources of supply—via pipelines—represents the most substantial opportunity to further develop the east coast gas market. The capacity trading reforms (which cost the industry millions of dollars to implement) have been in effect for less than 3 years and are already under review. In this context, we question whether it is appropriate that the proposed answer to modest usage of a newly introduced, still relatively unfamiliar system and the additional costs it has caused the industry to incur is to implement further structural change and additional implementation costs.
		
		• Assuming a stable regulatory environment can be provided, we are seeking to develop two projects that would facilitate a more efficient market and increase investments in and around Wallumbilla:
		  ○ The first project addresses supply and compression constraints at Wallumbilla resulting in increased access to market, creating a step change in number of participants; and
		  ○ The other project brings new participants to the market; it involves the construction of a new gas lateral which would facilitate multiple upstream producers in the Bowen Basin accessing the WGSH.

No.	Questions	Feedback
		Gas quality requirements • The complexities around the various gas quality requirements through the WGSH have not been addressed. The stringent lean legislative gas requirements of the LNG producers make the many theoretical gas trades required to achieve a higher level of liquidity impractical due to current infrastructure limitations. We recommend that Officials should further consider the extent and likely impact of gas quality requirements on trading activity at the WGSH.
3	Do you have any comments about the proposed objectives of this work?	• Efforts associated with the development of the reform roadmap could be better served by focusing on the more acute issue of the risk of a supply driven shortfall of gas supply on the east coast. The complex market dynamics leading to this shortfall risk will have a fundamental and long-term impact on the affordability and reliability of the supply of natural gas in Australia, beyond the nuances of short-term trading at the WGSH or on pipelines.

[1] Jemena, Submission on pipeline reform package exposure draft, 14 October 2021.

Chapter 3: Consultation focus 1: Wallumbilla Gas Supply Hub

Section 3.1 What are the potential problems?

No.	Questions	Feedback
4	Do you agree with the problems that have been identified for Wallumbilla GSH and what effect do you think they could have on meeting the objectives outlined in Chapter 2.4?	• While we agree with several of the problems identified in the consultation paper that may limit the number of potential participants, such as anonymity and prudential requirements, the assumption that a more liquid east coast market will necessarily put sustainable downward pressures on gas prices over the long-term should be subject to critical examination. We believe that increasing supply to market would have a larger contribution to downward price pressures than targeting increased liquidity within the Wallumbilla trading hub. As supply increases we may expect an increase in trading, however we expect bilateral trading to remain the dominant commercial mechanism. This is due to the fact that most gas customers need security of supply at known prices to manage their risks. • The current winter energy crisis in Europe demonstrates the potential downsides of over-reliance on spot markets. Liquid markets have exposed both sophisticated and unsophisticated participants to the inevitable supply and demand shocks of an energy transition. • We understand the Government's desire to bring the benefits of scale and liquidity such as those enjoyed by US consumers as a result of the large and highly liquid Henry Hub. However, fundamental differences in structure, market scale and infrastructure density mean that the Henry Hub is likely to remain an unrealistic benchmark in the medium term. • The Australian market is dominated by a small number of large participants and crosses vast geographical areas, requiring infrastructure of significant scale, being underpinned by long-term commitments. The participants at WGSH utilise the location to balance short term physical positions often as a result of operational factors, or opportunistically to exchange physical volumes. The WGSH participants do not all enjoy equal access to the physical pipelines and compressors. In this market true liquidity may be unachievable, as physical infrastructure constraints may impede incremental trading and in particular when the physical assets are held by a single party. • As an asset owner and an active investor in and around the WGSH, we cannot envisage a future circumstance where a market could be established in the Australian context that is both liquid and deep enough to provide sufficient signals to make the required long-term, capital intensive, investment decisions without bilateral customer agreements underpinning these investment decisions. • In addition, as noted in our response to question 2, the potential for additional regulatory and market uncertainly created by regulatory interventions if implemented in pursuit only of a more liquid trading market risk undermining signals and incentives for efficient long-term investment in infrastructure, which itself is critical to bringing new gas supply to market—the factor most likely to put downward pressure on gas prices over the long-term.

No.	Questions	Feedback
5	Are there any other problems that you think should be considered? If so, please set out what they are, what effect they may be having on liquidity at Wallumbilla GSH, and how these problems could be addressed.	**Address connectivity constraints at Wallumbilla to increase access to the market** • Jemena believes that increasing the number of gas suppliers connected to the WGSH would increase supply and liquidity. Competition can be introduced via competition in infrastructure and services that underpin the physical nature of the WGSH. Specifically, additional compression capacity which facilitates increased access by market participants to the high pressure side of the WGSH and increased connectivity between the pipelines servicing the WGSH would act as a catalyst for additional gas supply to come online. • Improved connectivity could enable gas from northern producers to flow to southern domestic markets and export markets and provide additional capacity to Queensland's Gladstone industry hub, where demand is increasing. Jemena is open to discussions with all interested parties regarding additional infrastructure investment to boost supply. **Facilitating multiple upstream producers in the Bowen Basin** • Jemena has been an active participant in the recent Bowen Basin pipeline study commissioned by the Queensland and Australian Governments, during which we highlighted the opportunity to develop a new open access, multi-user pipeline which could bring supply from multiple new gas producers into the south east Queensland market. Doing so would require a staged approach to pipeline development, with a pipeline to be constructed with an initial level of uncontracted capacity to accommodate future increases in the number and size of Bowen Basin producers to leverage pipeline economies of scale and ensure the most efficient delivered price of Bowen gas over the long-term. However, as set out in Jemena's response to the gas pipeline regulation draft reform package,[2] the lack of a workable greenfield exemption mechanism which adequately addresses regulatory risk for such open-access pipelines will severely hamper our ability to continue pursuing this most efficient solution to connect the Bowen Basin to the east coast gas market.

[2] Jemena, Submission on pipeline reform package exposure draft, 14 October 2021.

No.	Questions	Feedback
6	Are there structural issues regarding the nature of supply and demand for gas in Australia which could impact the success of reforms aimed at increasing liquidity of gas markets?	• We believe that increased gas supply to customers is the most critical factor to address concerns around gas prices. To deliver additional supply, increased investment is needed in new gas storage facilities and large scale upstream developments. However, for long-term, capital intensive investment decisions, infrastructure providers require investment certainty provided by long-term contracts and a stable regulatory framework. We believe our ability to obtain the long-term contracts needed to underpin new investment is challenged by the ongoing level of regulatory change resulting from the range of recently (or soon to be) implemented reforms coupled with the proposals in the consultation paper aimed at increasing liquidity of gas markets. This is particularly the case in the context of regulatory changes targeted at increasing short-term liquidity which may also undermine incentives for shippers to enter into long-term transportation contracts, in part due to a perception that other shippers may be able to access the same infrastructure while making minimal (or no) contribution to its costs.

Section 3.2 How could these problems be addressed?

Section 3.2.1 Anonymised delivery

No.	Questions	Feedback
7	What benefits could anonymised delivery offer for gas market participants which could assist in achieving the objectives in Chapter 2.4? What do you think the costs and benefits of implementing such an option would be to your business in terms of your participation in the Wallumbilla GSH?	• For anonymised delivery to be successful it needs to be compliant with ‘Know Your Counter-party’ and ‘Anti-Money Laundering’ provisions.

No.	Questions	Feedback
8	What do you believe would be the most appropriate design for an anonymised delivery model at Wallumbilla GSH? (a) Is a model which emulates the CTP most appropriate for anonymised delivery of gas traded through the GSH? (b) What balancing regime represents the best trade-off of complexity and benefit to liquidity? (c) Would implementation via a Rule change or bilateral agreement be more preferable in terms of achieving the NGO?	• No comment.
9	In terms of an implementation roadmap, what importance would you place on addressing this issue and over what timeframe?	• As mentioned above, consideration must be given to what is required to comply with the 'Know Your Counter-party' and 'Anti-Money Laundering' provisions, and whether compliance can be achieved, before any further work is completed.

Section 3.2.2 Streamlining prudential requirements

No.	Questions	Feedback
10	Do you think there is likely to be a net benefit in harmonising prudential requirements across the east coast facilitated gas markets? What effect do you think this will have on your business, and suppliers and users more generally?	• We generally support harmonising prudential requirements. As an infrastructure operator, we perform routine credit checks for user Gas Transport Agreements (**GTAs**). Streamlining this process is welcome, but it is not seen as an impediment to conducting our business. However, as flagged in the consultation paper, changes to the prudential requirements may be complex and create new costs for market participants, therefore a detailed cost-benefit analysis is required in consultation with industry.

No.	Questions	Feedback
11	Do you think the introduction of the ASX physical delivery futures product will alleviate the current concerns around collateral requirements of forward-dated products? If not, please explain why.	• No comment.
12	Which option for sharing prudential requirements do you consider would be likely to offer best value for money? Are there other options that should be considered?	• No comment.
13	In terms of an implementation roadmap, what importance would you place on addressing this issue and how quickly do you think it needs to be addressed?	• No comment.

Section 3.2.3 Market making

No.	Questions	Feedback
14	Do you think a market making regime could make the Wallumbilla GSH better suited to your gas trading needs? Is a market making regime necessary in order to develop liquidity at Wallumbilla GSH or is this better achieved through other means?	• No comment.

No.	Questions	Feedback
15	What form of market making regime do you think would be most appropriate for achieving the objectives in Chapter 2.4? (a) What parties would be most appropriate to be market makers (and in what markets e.g. physical, financial)? Should this be voluntary or mandatory in terms of participation? (b) How do Energy Ministers ensure that there is minimal adverse impact to participants selected as market makers in such a regime? Are there elements of the design of market making regime that could assist in minimising the implementation cost? (c) What role (if any) could energy market bodies and/or governments play in facilitating a regime at Wallumbilla GSH?	• No comment.
16	Does a market maker within the ASX physical futures product sufficiently reduce the need for an alternative market making regime for Wallumbilla?	• No comment.
17	In terms of an implementation roadmap, what additional work is required to consider the merits of market making regimes and to assess the cost and benefits of different designs?	• No comment.

Section 3.2.4 Virtual hub design

No.	Questions	Feedback
18	What benefits do you think a virtual hub for Wallumbilla GSH could introduce and why? Do you think it could make it easier for your business to trade gas?	• No comment.
19	Do you have views on the design details that would need to be considered in designing a virtual hub, for instance which form of carriage model or balancing regime would be most appropriate?	• We agree that design of a virtual hub would require a multi-year program of consultation and implementation. • We note that the required physical gas settlement framework has not yet been deeply considered in the conceptual design, and that the importance of investment in compression upgrades and further interconnectivity are relevant considerations as outlined in our response to question 5.
20	What level of regulation should be imposed upon the hub operator? And what activities should be regulated as part of this? Should consideration be given to an independent hub operator?	• No comment.
21	Regarding the idea of expanding a virtual hub to encompass the SEQ trading location and the Brisbane STTM: (a) What additional benefit would this provide your business, and the gas market generally, compared to a virtual hub covering Wallumbilla alone? (b) What are the major risks associated with this proposal, particularly considering management of existing contracts and congestion? (c) Would a liquid trading hub be an adequate replacement for the mandatory Brisbane STTM?	• No comment.

No.	Questions	Feedback
22	In terms of an implementation roadmap, are there other considerations which should be considered for future consultation and assessment, if this option was to be investigated further?	• As mentioned above, the required physical gas settlement framework needs to be deeply considered in the conceptual design, including what compression upgrades and further interconnectivity is required.

Section 3.2.5 Other options considered

No.	Questions	Feedback
23	Do you agree with the initial analysis of these other options? Do you think there is merit in exploring these options further in order to assess whether they could contribute to meeting the objectives outlined in Chapter 2.4?	• No comment.
24	Are there additional options which should be considered by Energy Ministers in more detail?	• As set out in our response to questions 5 and 19, further consideration needs to be given options that address: ○ supply constraints (connectivity and capacity) at Wallumbilla to increase access to the market ○ facilitate multiple upstream producers in the Bowen Basin • Also, as set out in our response to question 22, consideration needs to be given to the required physical gas settlement framework in the conceptual design of a virtual hub, including what compression upgrades and further interconnectivity is required.

Chapter 4: Consultation focus 2: Pipeline capacity trading frameworks

Section 4.1 What are the potential problems?

No.	Questions	Feedback
25	Do you agree with the problems that have been identified with pipeline capacity trading frameworks and what effect do you think they could have on future liquidity growth in the east coast gas market?	Jemena is concerned that the review of the DAA and CTP mechanisms is too early and that some of the issues raised rely on assumptions of future market behaviour without clear supporting evidence. In addition, it is not clear to us how other recent reforms which are yet to be implemented will impact the mechanisms and the future liquidity growth in the east coast gas market. **The review is too early** ▪ We caution the implementation of further reforms until there is sufficient time to see evidence of how the market is impacted by the initial reforms, and those impacts are assessed against the Energy Ministers' objectives. The reforms should not be based on assumed future market behaviour which might potentially be inconsistent with the Energy Ministers' objectives. • We have many GTAs expiring by the end of 2022 (we expect that this is similar for other pipeline operators servicing the southern markets given the current limited supply certainty). As shippers recontract their positions, we will better understand what the potential impacts (if any) may be on future auction quantity limits (**AQLs**) in the DAA, and what available capacity there may be for other shippers and / or potentially to be traded through the CTP. Therefore, ideally, consideration of some of the matters raised in the consultation paper should be revisited in 2-3 years' time to enable informed decision making on the need or otherwise for further reform to the DAA and CTP mechanisms. **Consistency with recent reforms** ▪ Any further reforms to the DAA and CTP mechanisms need to be consistent with the proposed regulatory framework[3] which will apply to both scheme and non-scheme pipelines and is currently being implemented. In particular, any further regulation should be consistent with the two stronger and lighter form regulation tests.

[3] Improving gas pipeline regulation, Proposed legal package to give effect to the Decision Regulation Impact Statement, Consultation Paper, September 2021.

		Assumption that there is a lack of incentive to trade capacity on the CTP ▪ The consultation paper notes that the availability of significant capacity at no or negligible cost on the DAA may represent the single biggest reason for subdued usage of the CTP, particularly for shorter-term capacity. ▪ This outcome is no surprise given the Gas Market Reform Group's (**GMRG**) market design provides little incentive for shippers to buy capacity on the CTP when the DAA provides opportunity for shippers to acquire capacity at no or negligible cost. The consultation paper[4] also notes that participants don't want to sell capacity because they prefer to retain it to manage short term risk, and that there is a strong demand correlation between shippers (winter peaks). We agree that these may be significant considerations for shippers when thinking about trading shorter-term capacity. However, these should not be viewed as problems which represent market failure, or which warrant intervention to solve. Rather, they reflect the high value shippers place on certainty in being able to meet their own (or their customers') needs, and of the highly seasonal nature of peak gas demand in some areas of Australia, particularly NSW and Victoria. ▪ Critically, we note that the consultation paper does not present any evidence to suggest that market participants would not turn to the CTP if the amount of capacity in the DAA was to significantly reduce in the future. ▪ Given the above, we do not consider there is a need to modify the CTP at this stage. **Assumption that recontracting behaviour may result in less contracted but un-nominated capacity for the DAA** ▪ We consider that great care must be taken in relying on this assumption to make decisions on proposed options to bolster the CTP or other means of accessing short term transportation services. The assumption should be subject to careful consideration and analysis, ideally supported by real life experience. As noted above, we have many GTAs expiring by the end of 2022. We are constantly engaging with existing and potential shippers regarding their future contracting needs, so are well-placed to appreciate trends in the market's future firm service requirements. ▪ The consultation paper notes that shippers in the future may seek 'more flexible shapes, a lower overall position and shorter timeframes for contracts' (p. 44). In our experience: o Where a shipper seeks a lower overall contracted position, it is primarily driven by a structural change in its own gas needs (e.g. a retailer forecasting lower future customer demand) or a structural change in the availability of gas supply to the pipeline. Shippers are not making these decisions because they are concerned about giving away capacity on the DAA – due to the take-or-pay nature of firm services, shippers have always had a strong incentive to match the size of their contracts to their requirements. Furthermore, given that reductions in shipper positions generally reflect structural changes in the demand and supply of gas in the markets upstream and downstream of the pipeline, the potential

No.	Questions	Feedback
		reduction in the availability of DAA capacity should not be seen to represent a market failure or even a barrier to liquidity in those markets. ○ The consequence of the current DAA is that shippers cannot rely on as available services (**AA**) to meet any flex as the DAA AQLs take priority to the AA service. As gas consumers, the industrial shippers must now participate in the DAA to achieve additional volumes rather than rely on their contracted positions. However, the DAA capacity can be picked up by traders who can offer the capacity to the industrials at any price. It is not clear yet how shippers propose to address this risk in the recontracted GTAs. ○ While the market is exhibiting an overall trend towards shorter, firm contract lengths, the biggest impact of this trend on future liquidity growth in the east coast market is the challenge it poses to pipeline operators' ability to underwrite investments in the new infrastructure necessary to bring online new gas supply. As noted in the consultation paper, several initiatives proposed to promote liquidity in wholesale markets over the short term may undermine shippers' contracting incentives and negatively impact pipeline investment, further impeding the development of markets over the long term due to the restrictive impact this would have on new gas supply. **Barriers to access of backhaul auction capacity** ▪ The purpose of the DAA mechanism is to free contracted capacity which is unnominated on a gas day. What is proposed in the consultation paper will result in more backhaul auction capacity in one direction than is contracted for. We are concerned that this is inconsistent with the intent of the gas market reforms and that it will reduce the incentive for shippers to enter long term contractual arrangements for services in the direction with less contracted capacity. We consider the associated negative impact on pipeline investment would be inconsistent with the NGO and the efficient allocation of pipeline costs between users. **Other matters** ▪ When considering reasons why participation may be low in CTP (or DAA), consideration must be given to the role of facilitated markets, such as the STTM, which effectively allow trade of pipeline capacity as well, given they are trading delivered gas. The ability to access a market for a delivered product (i.e. bundled with transportation) may represent a more attractive option for some participants (particularly smaller market participants with fewer resources and with smaller portfolios across the east coast market) than participating separately in wholesale and transportation markets.

[4] Section 4.1.1 (p 23).

No.	Questions	Feedback
		▪ Where shorter term primary services significantly displace the use of longer term services, the proportion of a pipeline's cost base which is recovered from users of short-term services is likely to increase, putting upward pressure on the prices of these services to ensure overall cost recovery for the asset. This could also be amplified by trends towards shorter term contracts being sought by customers and if there is a reduction in the amount of firm capacity which has been booked (which also means less DAA capacity made available, therefore higher reliance on short term primary products). Trends towards shorter term contracts and a reduction in revenue certainty are likely to increase pipeline operators' funding costs resulting in higher prices for users of both long- and short-term services.
26	Are there any other problems that you think should be considered? If so, please set out what they are, what effect they may be having on pipeline capacity liquidity, and how these problems could be addressed.	• See our response to question 25.
27	Do you agree that these identified problems are relevant to meeting the objectives in Chapter 2.4? If not, please explain why.	• Consistent with the objectives in chapter 2.4 of the consultation paper, there is the need to balance between introducing reform which establishes 'a liquid gas market that provides market signals for investments and supply' whilst at the same time ensuring 'the development of open and competitive markets.' The DAA and CTP mechanisms, along with the information and access obligations in Part 23 of the NGR, may arguably have increased the liquidity of gas capacity and contributed towards a more liquid gas market. In fact, the DAA has been utilised more than envisaged. What is not clear at this stage is the impact of the DAA and CTP mechanisms on the longer-term development of the broader gas market. In particular, what the impact will be on pipeline investment for new supply and market development over the long term, and what this means for gas prices. As discussed in response to question 25, we expect to understand more about the likely future impact of the DAA and CTP mechanisms over the next 2-3 years. • We note that in implementing further reform, the Energy Ministers must satisfy themselves that any further reform advances the NGO consistent with the legislated objective of the regulatory framework. In particular, to the extent that there may be conflicts between the Energy Ministers' objectives over the shorter term in implementing further reform, achievement of the NGO must take precedence.

Section 4.2 How could these problems be addressed?

Section 4.2.1 Reviewing fee structures and levels

No.	Questions	Feedback
28	Do the fees charged by AEMO for participation in pipeline capacity trading act as a barrier to further growth in usage? How could this be alleviated?	• No comment.

29	To what extent should pipeline operator fees be reformed in order to increase the efficiency of the market, noting the options outlined above?
	(a) Do you agree with the AER's initial findings that the fee structures imposed by pipeline operators did not represent a substantial barrier to trading?
	(b) Would an increased level of regulation on pipeline operator fees be warranted in order to better improve market outcomes? Are there any risks which could arise from this approach?
		• Given the AER's findings, that the Standardisation Cost Charges are a minor part of the total cost of transported gas and that we expect them to decrease, and that there is already an appropriate regulatory framework in the NGR relating to the recovery of these charges, we do not consider that any further regulation is required.
		• Pipeline operators are likely to be approaching the end of the period over which the initial IT/system expenditure required to implement the DAA and CTP platforms is being depreciated and recovered through fees. Whilst there will be a level of ongoing expenditure associated with these platforms, and some additional IT expenditure may be incurred as systems reach their end of life or in response to further regulatory changes arising from this or other processes, some pipeline operators' fees may reduce over the coming years. We also note that recent increased usage of the DAA on some pipelines may offset the recovery of pipeline operator costs and put downward pressure on fees.
		• We agree with the AER's initial findings, which have been demonstrated by recent DAA volumes. We also note that most of the capacity on the DAA has been won at $0/GJ or negligible cost, providing shippers with low overall transportation costs compared with shippers that have GTAs in place.
		• The NGR contain provisions which regulate the Standardisation Cost Charges. It is imperative for future investment that pipeline operators can recover their efficient costs, as per rule 634(2) of the NGR. We note the NGR also requires:
		  ○ Pipeline operators to publish the basis for their Standardisation Cost Charges on their websites (rule 634(4)), and
		  ○ The AER may, at any time, at the request of a transportation facility user or prospective secondary shipper or on its own initiative, review a standard OTSA or an agreement prepared in accordance with the exemption condition provided for in rule 611(6) including charges under the agreement (rule 635(1)).

No.	Questions	Feedback
		• We consider the current NGR arrangements for cost recovery appropriately allow pipeline operators to choose the structure and level of their Standardisation Cost Charges which they think is best suited to their pipeline and enables recovery of their efficient costs. We do not support a move to common fee structure and methodology, or common fee amount (all pipelines should be afforded the opportunity to recover their efficient costs over the same period of time). • With regards to other matters raised in the consultation paper: o We do not believe that recovery of fees through AEMO is appropriate because such a mechanism would be less transparent than the current arrangements whereby AEMO and the pipeline owners are accountable for the costs incurred and resulting fees charged. The Energy Ministers have already flagged concerns about the level of AEMO's fees which adding pipeline costs to the pool of AEMO's costs recovered will only make recovery of AEMO costs more problematic. More importantly, such a mechanism will blunt accountability on AEMO and the pipeline owners to minimise their costs. o We note that the recently proposed regulatory framework will apply a range of new measures to both scheme and non-scheme pipelines, and appropriately deals with the assets and services to be regulated. The new regulatory framework will involve the imposition of either stronger form or lighter forms regulation to all pipelines, and regulation on pipeline operator fees should be subject to regulation consistent with the new framework rather than introducing a new basis for regulation.
30	In terms of an implementation roadmap, what importance would you place on addressing this issue and how quickly do you think it needs to be addressed?	• We consider the regulatory framework for recovery of Standardisation Costs and the recent reforms on improving gas pipeline regulation already represent a significant constraint on pipeline fee recovery and that no further work is required to refine the arrangements for pipeline operator fees.

Section 4.2.2 Reviewing bidirectional pipelines restrictions

No.	Questions	Feedback
31	Are there specific pipelines for which access to backhaul capacity is an issue for participants? (a) Would an interruptible backhaul auction product on bidirectional pipelines such	• The consultation paper proposal to review the classification of bidirectional pipelines and calculate AQLs for an interruptible DAA backhaul product based on the predominant contracted pipeline capacity flow (i.e. resulting in firm forward haul and backhaul services) will mean that more AQLs

No.	Questions	Feedback
	as the one described above be feasible? If not, please explain why. (b) Is there a need to strengthen the conditions by which a pipeline can be made bidirectional? What risks could eventuate through a higher barrier to reclassification of pipelines?	will be made available at some points[5] on bidirectional pipelines than the underlying contracted positions. • Whilst bi-directional services enable the pipeline operator to offer firm services in both directions, they are quite different from firm backhaul services which are offset against forward firm haul service. Most notably, bi-directional pipelines often flow gas in only one direction at any one point in time depending on the demand for gas transportation services in any one direction. That direction may change from one day to another depending upon demand. When offered, there are separate contractual arrangements for the direction of the services on bi-directional pipelines, and pipeline operators sell capacity in both directions which ultimately results in lower overall transport charges to shippers. • The purpose of the DAA mechanism is to free up contracted capacity that is unnominated on a gas day. What is proposed in the consultation paper will result in more backhaul auction capacity in one direction than is contracted for. Not only is this inconsistent with the intent of the gas market reforms, but it will also reduce the incentive for shippers to enter contractual arrangements for services in the direction that has less contracted capacity. This could result in existing contacted shippers missing out on any reductions to average transportation charges result from increased overall demand for transportation services. The shippers with contracted positions on the pipeline will be subsidising the shippers transporting gas in the other direction on the pipeline. This is inconsistent with the NGO which aims 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. • It is also likely to result in some shippers obtaining access to an interruptible DAA backhaul product for negligible or no cost; that is, third parties are being given free access to services purchased by others. This is inconsistent with the economic concept of user pays, whereby the most efficient allocation of resources occurs when consumers pay the full cost of the goods that they consume. • This consultation paper proposal appears to be benefiting certain participants over others by allowing gas producers and gas traders to transport gas to trading hubs at potentially negligible or no cost and sell it at a market premium. It is difficult to reconcile why one part of the supply chain, the pipeline owners, would be prevented from charging for services which will directly increase the

5 Where pipelines are bidirectional, the backhaul service is sold as Firm Forward in a particular direction. A backhaul AQL on a single direction pipeline will match the Forward Haul AQL at that point. However, on a bidirectional pipeline the AQL will not match the Forward Haul AQL – the backhaul service point (which is classified as a forward haul) will have its own AQL based on contracted and nominated capacity. Depending on the pipeline and its contracted position, this may cause an imbalance of backhaul AQLs.

No.	Questions	Feedback
		returns to other participants in the market. Also, as mentioned above, the proposal is not freeing up contracted capacity; the capacity is available on commercial terms from pipeline operators.
32	In terms of an implementation roadmap, is there a preferred approach or other considerations which should be considered for future consultation and assessment, if this option was to be investigated further?	• We do not consider it appropriate to introduce reforms which go beyond releasing contracted but unnominated capacity. If Energy Ministers wish to consider the matter further, we believe further work is required to demonstrate the net benefits from adopting the proposed interruptible DAA backhaul product. In particular, careful consideration must be given to potential impacts on pipeline investment and on the prices of services for existing shippers, and to ensure it does not result in an outcome where shippers can avoid paying the appropriate cost for the services on offer.

Section 4.2.3 Alleviating issues around auction timing

No.	Questions	Feedback
33	Would shifting forward the nomination cut-off time within the gas day present any difficulties? How might this impact the certainty for gas users to nominate for the next day? (a) Would the benefit in shifting forward the nomination cut-off time, and consequently the DAA, be sufficiently material to justify change?	• Changing the nomination cut off times to bring all subsequent processes forward by one hour will present some pipeline operating difficulties. This includes the time, effort and cost of amending GTAs to reflect new nomination cut off times, updating systems for automated scheduling, as well as rearranging staff coverage times during the nomination period and for the checks needed to be completed prior to auction. • We do not believe that bringing forward the nomination cut off time will address the issues identified in the consultation paper – specifically the issues around interaction with STTM Bids, given that the STTM Bids for D+1 are made at 11:30am on D-1. Even if the nomination time is brought forward by one hour, shippers will not know the outcome of the auction when making STTM bids. One issue which will be addressed is the DAA nomination times being earlier in the gas day, however in our experience shippers have not raised this as a concern. • Since AQLs are determined by calculating capacity which is contracted but not nominated, the auction must be run after the nomination cut off time for primary shippers. Nominations for auction services must logically follow even later to allow for the auction results to be determined and communicated.

No.	Questions	Feedback
34	Are there thoughts on the usefulness of an automated nomination process for auctioned capacity in order to alleviate timing concerns from smaller participants? How might this be best implemented?	• We can confirm we have not received any recent negative feedback from shippers in relation to timing of the auction. • From a pipeline operator perspective, we need to consider the required changes to our system to automate DAA nominations and the associated costs. • Based on our experience dealing with small shippers who participate in the DAA, some smaller shippers source gas after their DAA bids are accepted/won. If nominations are automated there is a risk that these smaller shippers may not have gas sourced for use. Further engagement with smaller market participants is necessary to understand how they would manage this risk.
35	In terms of an implementation roadmap, what importance would you place on addressing this issue and how quickly do you think it needs to be addressed?	• Pending feedback from shippers as to whether this is a useful change, we consider this to be a potentially higher priority than other potential reforms set out in the consultation paper. If it is something shippers think is useful, further consideration is required to understand what changes are required to systems and the cost. If this change is implemented, arrangements should be left unchanged for 2-3 years to understand how this change impacts the liquidity of the market before any further consideration is given to the initiatives considered in section 4.2.4 (reviewing firmness of auction product) and section 4.2.5 (improving the usefulness of the capacity trade platform) of the consultation paper.

Section 4.2.4 Reviewing firmness of auction product

No.	Questions	Feedback
36	Should the firmness of the auction product as initially recommended by the GMRG be revisited, given the outcomes of the auction and use of the CTP? (a) What risks could shifting to a hybrid auction introduce (e.g. impact on investment signals)? What measures could be put in place to limit any impacts?	• We remain very concerned that including firm DAA products (even though only sold on a day ahead basis) will undermine the services in our GTAs and negatively impact market certainty for customers and their willingness to enter long term GTAs. • For example, for a pipeline like QGP which is fully contracted (mostly with industrial customers) a firm DAA product creates the risk that we will not be able to accommodate renominations by shippers with firm MDQ to meet their operational requirements and our contractual obligations given there will be no available capacity to do so. This means that the firm DAA product will negate the firm rights of our customers who pay for these services, and allow traders and other shippers to obtain equal rights for the DAA most likely at zero or negligible cost. We are concerned that the risk associated with reduced ability to submit renominations over primary capacity may particularly impact gas powered generators, especially now that 5 Minute Settlement has been implemented in the NEM. Renomination rights currently retained by shippers in their GTAs are critical to ensuring that gas (and electricity) can be delivered to customers with certainty to meet changes in usage requirements and the available generation mix, which is becoming increasing volatile as renewable energy replaces traditional energy generation. • We are also concerned that firm DAA products in turn will make it difficult for infrastructure investors to commit to new long asset life infrastructure. This is because a firm DAA product may undermine the willingness of shippers to commit to firm services, or the same level of firm services as in the past, over time when another party could potentially get the same rights on a day ahead basis. As a consequence of underwriting the investment the primary shippers are penalised by the DAA regime as the capacity they contracted to make the project viable is given away to third parties. This disadvantages the primary shipper as their products become less competitive to those of secondary shippers who may not pay, or pay very little, for transportation. • We also note that managing scheduling and curtailments is complex for pipeline commercial operations, and adding a firm DAA product would only further heighten this. It would be inequitable if, where events cause curtailment of capacity, primary shippers who have reserved capacity on long term contracts will be curtailed at the same rate as DAA customers. • Lastly, we strongly believe that system security cannot be put second to increased liquidity in energy or capacity markets. The DAA has appropriately increased liquidity and the mechanisms should only be reassessed when there is more information on how shippers contract in response to the DAA and CTP mechanisms.

No.	Questions	Feedback
37	In terms of an implementation roadmap, what additional work is required to consider the merits of reviewing the firmness of auction products?	• Given the complexity of the matter, the potential risks to the incentives for infrastructure investment, and the current lack of clarity of issues that need to be addressed, we believe this matter should only be considered further when there is clarity on how shippers' new and recontracted GTAs are impacted by the DAA, and what this means for the CTP and the ability for pipeline owners to obtain long term GTAs underpinning the necessary investment. We expect to have this clarity in the next 2-3 years.

Section 4.2.5 improving the usefulness of the Capacity Trading Platform

No.	Questions	Feedback
38	Could the usefulness of the CTP be improved through a simplified product offering or coordinated trading mechanism for secondary capacity? How could simplification best be achieved?	• As noted in the consultation paper, shippers are typically able to win significant auction capacity on the DAA at low prices and there is less of an incentive to seek capacity on the CTP. Even with a simplified product offering this is likely to remain the case while the DAA is in place and there is excess contracted but unnominated capacity available. This is not unsurprising given the GMRG's market design provides opportunity for shippers to acquire capacity on the DAA at no or very little cost when there is excess contracted but unnominated capacity. • The extent of the problem suggested in the consultation paper around pipelines having short term market power is far from clear, noting that the ACCC comparisons to pricing of services is based on very different international markets. There are appropriate commercial incentives for pipeline operators to sell spare capacity and stipulating an obligation on them to offer a specified proportion of (or all) uncontracted capacity on the CTP is unnecessary. • In any case, the soon-to-be implemented reforms on improving gas pipeline regulation[6] are specifically designed to provide a strengthened regulatory mechanism to deal with concerns around pipeline service provider market power. Under the reforms anyone can initiate a scheme pipeline determination process and seek to apply full regulation to a non-scheme pipeline which it believes is exercising market power, including in relation to short term services. If the AER determines the pipeline should be a scheme pipeline, short term services could become a regulated reference service.

[6] Improving gas pipeline regulation, Proposed legal package to give effect to the Decision Regulation Impact Statement, Consultation Paper, September 2021.

No.	Questions	Feedback
39	Would increasing access to primary capacity products on pipelines through the CTP result in a more efficient gas market, and improve flexibility for shippers and buyers? Is this an attractive alternative to bilateral contracting for short-term primary capacity? (a) What products could be made available? Is the CTP the most appropriate platform to make these products available? If not, please explain why. (b) How could pricing for these products be set? How could any incentives for economic withholding be addressed?	• Where possible, the gas transportation market should be subject to competitive market forces. This means that trade of uncontracted capacity on the CTP should be optional so as to avoid distorting market signals for firm contracting of capacity. • As mentioned above, it is critical to preserve incentives for contracting of long term firm services, otherwise pipeline owners will not invest in new infrastructure, which will restrict development of new gas supplies and negatively impact development of the east coast market over the long term – putting pressure on prices. It is too early to know what the impact of the DAA and CTP mechanisms will have on long term contracts, but, as noted in the consultation paper, there is an expectation that shippers will reduce the level of potential contracted but un-nominated capacity that ends up in the DAA. This may mean that capacity is freed up for other shippers to enter into supply contracts and / or the CTP is utilised more than it is now.
40	In terms of an implementation roadmap, what additional work is required to consider the merits of trading primary capacity products on the CTP?	• As per our response to question 37, given the complexity of the matter, the potential risks to the incentives for infrastructure investment, and the current lack of clarity on issues yet to be addressed, we believe any changes to the CTP to allow trading primary capacity products should only be considered once there is clarity on how shippers' new and recontracted GTAs are impacted by the DAA, and what this means for the CTP and the ability for pipeline owners to obtain long term GTAs underpinning the necessary investment. We expect to have this clarity in the next 2-3 years. We think voluntary participation in the CTP is an essential feature that should be guaranteed as part of any proposed implementation.

Section 4.2.6 Other options considered

No.	Questions	Feedback
41	Do you see potential benefit in any of these other options which would help to achieve the objectives outlined in Chapter 2.4 and may warrant further exploration?	• Jemena agrees that no further work is required on the identified options.

No.	Questions	Feedback
42	Are there additional options which have not been explored or identified here and should be considered by Energy Ministers in more detail?	• No comment.

Chapter 5: Other enabling framework reform options

Section 5.1 Third-party access to gas infrastructure

No.	Questions	Feedback
43	Do you think there is currently an issue with third-party access to gas facilities other than pipelines? Would a regulatory access regime for these facilities lead to better outcomes for the gas market and support achievement of the Energy Ministers' vision? (a) What types of facilities should be the focus of a third-party access regime (if any)? To what extent are the issues associated with these facilities similar to or different from the issues considered in the Pipeline RIS?	• We consider that any 'issues' being experienced by market participants with respect to non-gas pipeline infrastructure appear consistent with a workably competitive market standard adopted by regulatory bodies and policy makers in Australia and therefore are unlikely to warrant introduction of some form of access regulation. Access regulation should only be applied where it is demonstrated that benefits clearly outweigh the costs, and furthermore, any reforms relating to non-pipeline gas infrastructure should be applied consistently between gas producers and infrastructure providers to avoid distorting investment incentives. This has not been the case with previous reforms targeted at pipelines. • We encourage a greater focus on matters identified in the 2021 National Gas Infrastructure Plan (**NGIP**), particularly in facilitating increased infrastructure investment, including in a diverse range of new infrastructure. • If the government decides to continue with a process to explore the possible introduction of some form of access regulation of non-gas pipeline facilities, then we consider that a properly constituted inquiry should be undertaken by the Productivity Commission which has a strong track record in undertaking expert and balanced inquiries of economic regulatory questions in Australia's East Coast gas markets. This includes consideration of potential interactions or inconsistencies with Part IIIA of the Competition and Consumer Act 2010, including its exemption for production facilities. • We consider that introducing economic regulation of non-pipeline facilities is unlikely to be justified given that:

		- In the long term, non-pipeline infrastructure operates in a market with competing technologies, and the range of competing options are increasing. For example:
		  - the NGIP has identified the need for new non-pipeline facilities, including LNG terminals and the Golden Beach storage project in Victoria
		  - there are a range of private sector developers with different non-gas pipeline development options, including gas storage and LNG terminals
		  - gas storage pricing needed to support gas power generation is increasingly competing with batteries and pumped hydro storage
		  - gas producers can provide swing services
		  - gas storage services can be provided by gas pipeline laterals (for example, Jemena's Colongra Gas Transmission and Storage Pipeline).
		- Pricing for unregulated storage services will reflect the demand-supply balance in a workably competitive market. Current Iona and Dandenong storage pricing is likely to reflect the tightness of the gas capacity market in Victoria, and these prices are likely to be acting as signal for investment. Pricing will likely moderate and storage capacity be made more available to market participants if new investments such as those identified in the NGIP are completed.
		- Efficient pricing of storage is complex and requires responsive and flexible decision-making processes, which is becoming increasingly important in today's rapidly changing market. Regulated access pricing processes by contrast tend to be slow and unresponsive to changing market conditions.
		- The International third-party access regimes for storage (Box 5.2 of the consultation paper) have limited applicability to Australia's circumstance given these gas markets are many times larger and Australia's energy market is undergoing a more rapid transition.
		- We encourage the Federal Government to adopt a consistent strategic approach to any interventions in the gas market. The government has correctly identified the need for new non pipeline infrastructure and its policies need to encourage the investment.
		• More broadly, we also note that this question brings into focus the matter of ringfencing, which is currently under consideration in two other reform processes (the Pipeline RIS reform package and the ongoing consideration of extending the national gas regulatory framework to hydrogen blends and renewable gases). For example, Senior Officials note the potential market benefits of processing facilities being operated on an open-access basis by midstream infrastructure owners. However, our response to the Energy Ministers' Pipeline RIS reforms on improving gas pipeline regulation, dated 14 October 2021, highlighted that the extension of the ringfencing requirements in Part 2 of the National Gas Law (**NGL**) to non-scheme pipelines risks the unintended

No.	Questions	Feedback
		consequence of requiring our processing facilities for the Atlas and Roma North Pipelines to be ringfenced from the respective pipeline businesses. If this were to occur, then we will be prohibited from refining gas to ensure it is fit for purpose and suitable for transportation. If the definition of 'related business' is not clarified to address this issue, we expect that transitional arrangements be included in the package so these facilities become exempt from the ringfencing obligations in Part 2 of the NGL reflecting that these commercial and contractual arrangements were made prior to the reforms being proposed. Furthermore, a standing exemption would be required for prospective processing facilities, which would be unintendedly captured by the ringfencing rules, to avoid posing a barrier to the development of such additional facilities by midstream operators in the future.
44	Are there alternatives to implementing a third-party access regime for this kind of infrastructure, such as an independent body like AEMO or governments owning and/or operating infrastructure such as storage or compression?	• In general, we do not support government ownership or operation of non-pipeline services such as storage or compression services. • As discussed in the answer to question 43, there are already a range of private sector developers of non-gas pipeline infrastructure facilities – and more are willing to invest. Government ownership of such services risks suppressing private sector interest in developing investment options due to perceptions of government entities acting in an uncommercial manner, such as creating excess capacity (through prematurely committing to investments or oversizing of capacity) or seeking rates of return and pricing which do not adequately reflect the project risk. This risk is likely to reduce incentives for competition, efficiency and innovation.
45	In terms of an implementation roadmap, what additional work is required to consider whether access regulation should be extended to other forms of gas infrastructure? What risks exist with regards to the introduction of any regulatory regime?	• As discussed in the answer to question 43, if the government decides to continue with a process to explore the possible introduction of some form of economic regulation of non-gas pipeline facilities, then we would support and encourage the establishment of a properly constituted inquiry undertaken by the Productivity Commission. This would include clarity on the extent of any problem and the risks to investment associated with the imposition of access regulation. • However, the Pipeline RIS ringfencing changes, which propose limiting the potential for midstream companies to develop open-access processing facilities in future, should be considered urgently as part of Pipeline RIS work if they haven't already been.

Section 5.2 Improving contracting practices to support greater on-screen trading and liquidity

No	Questions	Feedback
46	What do you consider to be the main benefits of off-screen bilateral contracting arrangements (for example, under an MSA) as compared with on-screen trading through the Wallumbilla GSH? (a) Are there any contracting practices associated with the Wallumbilla GSH that you consider currently act as a disincentive to on-screen trading? (b) What further procedural, regulatory or contractual changes would encourage increased on-screen trading through Wallumbilla GSH and would support your gas portfolio needs?	• No comment.
47	How important is it to you to ensure confidentiality of commercial terms like price and volume when trading? To what extent would the option to anonymise delivery of gas at Wallumbilla GSH (outlined above) address confidentiality concerns?	• No comment.
48	Are there are regulatory or other barriers preventing the entry into the market, or effective operation, of brokerage service providers?	• No comment.

Section 5.3 Potential government support for infrastructure

No	Questions	Feedback
49	Do you think that government support for infrastructure would be an appropriate means of helping achieve the objective of more liquid trading in capacity/gas? (a) Is there a risk that government support could crowd-out and displace private investment? (b) Is there a role for the market bodies or government as independent owners or operators of infrastructure, including as an independent operator of the Wallumbilla GSH?	• While we welcome government's consideration of the need to support the development of gas and gas infrastructure in Australia's energy system, we strongly believe the mid-stream sector has been an enabler and not a barrier to the delivery of additional gas supply. The Australian mid-stream sector has a strong history of developing transportation infrastructure when economic upstream resources are sufficiently proven and a market for sale established. Jemena's nation-building $800 million Northern Gas Pipeline is a testament to this. • Direct government support in midstream infrastructure should only be considered in limited circumstances, and should be targeted at projects which will increase new gas supply given the long-term structural benefits this would have on the east coast market's development. • There may also be instances where government, through vehicles such as the Northern Australian Infrastructure Fund, may be able to facilitate more efficient private sector investment, for example by addressing differences in timing between new suppliers coming online within a gas basin and the need to construct infrastructure early in the basins' development cycle in order to allow for the most cost-efficient route to market for gas over the long-term. • Finally, it is important that any government action – either directly or via regulation, such as the pipeline RIS regulatory framework – does not increase risk with the corollary of reduced private sector investment and gas supply, or inefficient increased investment costs (which will be ultimately borne by consumers).

Section 5.4 Access to regional pipelines

No.	Questions	Feedback
50	Do you see regional pipeline access as an issue that requires addressing as part of achieving the Energy Ministers' objectives? (a) Does the ACCC's proposed capacity surrender mechanism represent an appropriate means of addressing regional pipeline access issues? (b) Do you have comments on the other potential options which have been explored above? If so, please explain.	• Changes must be targeted only at a pipeline where a specific problem is identified. While the consultation paper and the ACCC refer to 'regional pipelines' as smaller transmission pipelines and laterals of major pipelines, this still represents an extremely broad set of assets – the existence on which the 'capacity hoarding' problem is far from clear. • Although all pipelines will be required to provide access to a new party when requested under the Pipeline RIS reforms, there are some pipelines where it is unlikely that another party would seek access (for example, Jemena's Colongra pipeline which serves a single power station). The initiatives suggested in the consultation paper (e.g. extending the DAA to smaller pipelines, or the requirement that all pipelines be required to have allocation arrangements in place) should not apply to single user pipelines (or to pipelines that do not currently provide third party access) until a second user has requested access. We note the Pipeline RIS package contains similar mechanisms to exempt pipelines not providing third party access or which have a single user from information disclosure requirements. This will still allow such initiatives to work where multiple parties wish to access a pipeline, but will avoid imposing additional costs where there is no benefit.
51	In terms of an implementation roadmap, what importance would you place on addressing this issue and how quickly it needs to be addressed?	