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27 June 2025

ISP Team
Australian Energy Market Operator
Level 22, 530 Collins Street
Melbourne, Vic 3000

Submitted via: ISP@aemo.com.au

Re: Draft Gas Infrastructure Options Report Consultation

Dear Ms Christie,

Jemena welcomes the opportunity to respond to the Australian Energy Market Operator's (AEMO) Draft Gas Infrastructure Options Report Consultation.

Jemena owns and operates a diverse portfolio of energy assets throughout northern and east coast Australia. With more than $12 billion of major gas and electricity infrastructure, we deliver energy to millions of households, institutions, and industries every day.

Our assets include the Jemena Gas Network in New South Wales, the Jemena Electricity Network in northwest Melbourne and gas transmission pipelines such as the Eastern Gas Pipeline, Darling Downs Pipeline, Queensland Gas Pipeline and the Northern Gas Pipeline. In addition, our group includes Zinfra, an energy services business, which provides project management, construction, operations and maintenance services for the electricity and gas sectors.

For this reason, we are uniquely placed to understand the planning and operating of the energy system 'as a whole', and how the electricity and gas sectors can support the objective of delivering low carbon, reliable and resource efficient energy services, at least possible cost for society.

Jemena understands the need to develop and include the Gas Infrastructure Options Report in the 2026 Integrated System Plan (ISP) process, as an essential step toward embedding credible, scenario-neutral gas in its modelling. This whole-of-system approach is essential to minimising total energy system costs and delivering reliable, lower emissions outcomes for consumers.

At the same time, we note the inherent risk of unduly favouring particular infrastructure options if underlying cost and capability inputs are incomplete or understated. While the draft GIOR is explicitly described as scenario-neutral, assumptions that favour one class of infrastructure over another could unintentionally discourage commercially viable projects and over allocate capital to higher-cost alternatives. Therefore, maintaining a balanced, technology agnostic dataset is critical to maintaining investor confidence and ensuring efficient market signals.

To that end, Jemena recommends that AEMO strengthen its gas infrastructure costs, as in our view the current dataset misses important components. These have been specified in the appropriate consultation questions in Appendix A. Further updating escalation indices for materials and labour costs will ensure that cost signals reflect current market conditions and parity amongst asset classes.

Furthermore, we believe that greater clarity regarding the modelling sequence for gas shortfalls is required, as the current explanation can be interpreted as curtailing gas powered generation before least-cost gas infrastructure options are tested, particularly paragraph 3 on page 26. To avoid misinterpretation Jemena proposes replacing the existing text with:

"Where a zone shows a forecast gas shortfall, the model will first optimise the least cost combination of gas supply, storage or pipeline expansions to remove the constraint. Alternative firming technologies will only be selected when those gas options are uneconomic or untimely."

Finally, Jemena invites AEMO to include a high-CAPEX sensitivity scenario, in order to test the robustness of the least-cost development path. These sensitivities may include a higher percentage of materials costs, labour or key components such as steel. Similar stress tests are already standard practice in the Transmission Cost Database and would provide a no-regrets check on potential cost overruns.

Jemena looks forward to continuing its engagement with AEMO and would welcome the opportunity to discuss input assumptions before the Final GIOR is released. We would also like to note, that in the eventual case the GIOR highlights material infrastructure constraints in certain areas of the network, Jemena encourages AEMO to test additional, market-led solutions, such as biomethane injection into existing networks, which may prove more cost-effective than large-scale electrification of existing industrial, commercial and residential gas demand.

For more information regarding Jemena's submission or to arrange a discussion please contact Adriano da Costa, Senior Policy Adviser via adriano.dacostaesilva@jemena.com.au.

Yours sincerely,

Georgie Wright,

A/Executive General Manager Gas Markets

Appendix A Consultation questions

Draft Gas Infrastructure Options Report 2025

<table>
<tr><th>Question</th><th>Jemena’s response</th></tr>
<tr><td>1. Do you have any feedback on the gas infrastructure base costs, adjustment factors and escalation indices provided by GHD?</td><td>Jemena commends AEMO for publishing a transparent cost library, however, our benchmarking against recent East Coast projects shows that several inputs need refinement if the GIOR is to remain technology neutral.

The baseline AUD$75k per inch-kilometre is for a Class 600 specification pipeline. Most new long-distance builds now proceed at Class 900, where thicker line pipe and the associated construction handling and welding push delivered costs above AUD$100k per inch-kilometre. We therefore recommend adding a Class 900 cost curve to the current baseline.
The large distances, and potential volumes, in the Northern Territory will likely require larger diameter pipelines than the 20 inch maximums tabled. 30” and above long-distance transmission pipelines have previously required importing machinery and skilled personnel, requiring different cost benchmarking. We therefore recommend adding a large bore transmission cost curve to the current baseline.
Location and mobilisation premiums also need to be reconsidered. A flat “Remote = 1.4” multiplier understates the camp, logistics and environmental-offset costs typical of very remote locations such as inland Queensland and the Northern Territory, while short (<25 km) laterals lack a mobilisation factor even though fixed set-up costs dominate such jobs. We suggest increasing the Remote factor and introducing a short-lateral multiplier. The same regional factors should apply to pipeline stations and linepack laterals. Similarly, a review of the Remote factor for Compression & Processing Facilities should also be considered.
Pipeline stations should consider inclusion of a line-item for live hot-tap tie-ins, typically several million dollars on large diameter, high-pressure steel pipes.
Our internal review also shows that storage laterals are currently not reflective of market concepts, as the dataset caps pipe diameter at 36 inches, design to Class 600 pressures, and prices the full nominal length, yet a 42-inch, higher pressure specification can achieve the same linepack with a shorter route or fewer strings. By not scaling cost with length saved, the model risks biasing against linepack storage and in favour of longer trunk pipelines or non-gas firming. Adding a DN1050 option and allowing length adjustments when pressure ratings increase would correct this.
On escalation, the steel index presumes a real 2 per cent decline after 2027. Given recent volatility, Jemena recommends updating the index annually and publishing a high-cost band. Compression costs (A $3–6.4 million per MW) appear reasonable, provided the proposed location multipliers apply to balance-of-plant as well as package equipment.

Finally, Jemena notes that biomethane plant and connection is already embedded in the ACIL Allen LCOE curves from the prior Draft IASR 2 consultation; we therefore ask AEMO to confirm these costs are not repeated in the GHD capex library to avoid double-counting.</td></tr>
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2. Do you have any feedback on the methodology for the gas infrastructure base costs and forecasts provided by GHD?	Jemena appreciates the disciplined framework GHD has adopted, deriving bottom-up component rates, applying location and terrain adjustment factors, and then indexing those costs through a single set of escalation indices. In principle this provides a transparent, scenario-neutral platform that can be updated as market conditions evolve, and is consistent with the "technology-agnostic, whole-of-system" philosophy we have previously endorsed in AEMO consultations. That said, several aspects of the methodology warrant refinement to ensure the ISP's investment signals remain robust: • GHD characterises its deliverables as an AACE Class 5 concept study. Our own benchmarking suggests that the ±50–100 % uncertainty band inherent in Class 5 estimates is evident in the current model, though we believe that the adjustments suggested in question 1 would improve its accuracy within that range. • For consistency we reiterate the need for a Class-900 uplift (see Q-1). • Location factors are currently applied to linear assets but not to pipeline stations (metering, pigging etc.). Given civil works and labour costs vary by 20-40 % between coastal and remote settings, a simple regional multiplier for stations would materially improve accuracy. These adjustments will tighten the Class-5 range and keep investment signals robust.
3. Do you agree with the proposed forecasting approach of applying a single set of cost escalation indices for gas infrastructure components across all ISP scenarios?	Jemena accepts the practicality of applying one national set of escalation indices across all ISP scenarios, provided the indices are updated annually and published in full. This cadence will capture rapid swings in key inputs. To preserve scenario-neutrality we also recommend a high-cost sensitivity band, for example, the upper-quartile forecast or a flat +25 percent uplift, applied specifically to the steel-intensive and labour-heavy cost components identified in the price-forecast workbook. This would test whether the Optimal Development Pathway remains least-cost under a tighter commodity market, thus mirroring the high-CAPEX stress-test in AEMO's Transmission Cost Database.
4. Do you have any feedback on AEMO's use of GHD's component costs in costing gas infrastructure options?	Jemena supports AEMO's decision to cost every infrastructure option with a common set of GHD component rates and multipliers; this ensures internal consistency. However, the same consistency has not been applied to the cost of the gas itself. GHD's costing approach includes the "cost of gas supply from field, from field production costs published with the 2025 GSOO" (factor S in Appendix 1)[1]." This approach ignores the fact that gas is not sold at cost of supply, but rather at a market price as negotiated under Gas Sales Agreements. The average cost of production in the 2025 GSOO for 2P Bowen-Surat reserves of $3.38/GJ as cited by Rystad Energy as "not intended to reflect gas sale prices, only the marginal cost of actually supplying the gas"[2]; in comparison, the average price at which gas was delivered to the east coast in 2024, as reported in the ACCC's most recent report, was

[1]AEMO Gas Infrastructure Opportunities Report, Appendix A1 (https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-gas-infrastructure-options-report/draft-2025-gas-infrastructure-options-report.pdf?la=en)
[2]AEMO GSOO 2025, G25 Reserves Cost assumptions, Production Costs Sheet (https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/gsoo-supply-data.zip?la=en)

	\$13.58-\$14.51/GJ[3]. Given the cost of the gas molecule has a much larger impact on the delivered price of gas than the transportation cost, using cost of supply will always weight towards domestic field developments vs LNG terminals as the latter will be based on international price markers. Jemena proposes that AEMO refrain from using cost of supply as it is not reflective of the price at which gas will be sold. The model should instead consider a range of likely market prices at which gas would actually be sold.
5. AEMO has proposed to limit sources of new natural gas supply to known contingent (2C) resources provided via the Gas BB and GSOO surveys. Should other sources of new gas be included?	We note that LNG import terminals appear in the GSOO 'supply-development' dataset and are therefore already available to the GIOR; therefore, Jemena supports retaining this treatment to ensure imported gas is assessed on the same basis as domestic 2C resources.
6. Of the list of gas infrastructure options mentioned in Section 3.2.2 and provided in Appendix A2, are there any options that should not be included, or any further options that should be considered?	Jemena has provided an updated list of infrastructure options currently contemplated for its gas transmission assets in Appendix 2. However, Jemena further notes that this list is not exhaustive and may change as market dynamics evolve.
7. Will AEMO's proposed gas supply and pipeline zone limitations be effective in limiting fuel availability for GPG?	Jemena agrees that daily fuel limits set at the 13 gas supply and pipeline zones are a pragmatic way to translate upstream and transport constraints into the ISP. The method will be effective so long as the model sequence is clear: first test the least-cost mix of gas supply, storage or pipeline expansions to relieve a shortfall; only then, if those options are uneconomic or untimely, curtail GPG or substitute with non-gas firming.
8. Considering the purpose of the assessment, is it reasonable to apply priority to residential, commercial and industrial customers ahead of GPG?	Jemena supports giving first priority to residential, commercial and industrial customers, as this mirrors real-world market obligations and social expectations. Applying the hierarchy in the modelling is reasonable so long as the demand forecasts underpinning those sectors are transparently documented, refreshed each cycle and published alongside the GIOR.

[3] ACCC Gas Inquiry (https://www.accc.gov.au/about-us/publications/serial-publications/gas-inquiry-2017-30-reports/gas-inquiry-march-2025-interim-report-gas-supply-agreements)

Appendix B

Updated List of Jemena Infrastructure Options

Option	Components or description	Source	Type	Zone	Capacity	Conditions
EGP reversal stages 1	Reversal of EGP compressors VicHub connection expansion	GSOO	Transport	Gippsland	EGP reversal 1: 200 TJ/d from Port Kembla to Longford (plus additional 70TJ/d capacity south from Orbost)	In Progress - Will be complete in Q1 2026
Expansion of Sydney MSP delivery	Expansion of EGP capacity to supply Sydney / MSP	GSOO	Transport	Gippsland	Allows up to 440TJ/d delivery from Port Kembla to Sydney/MSP	
EGP reversal stage 2	Additional compression on the EGP				325 TJ/d from Port Kembla to Longford (plus additional 70TJ/d capacity south from Orbost)	EGP reversal stage 1
Moomba to Sydney Pipeline to EGP compression (Stage 3)	Compression at Wilton to allow flow from MSP to EGP	GSOO	Transport	Gippsland	~100TJ/d per compressor, sized to market requirements	EGP reversal stages 1 & 2 complete
Southern Highlands Pipeline	Connects EGP (Oallan / Albion Park, NSW) to MSP in support of GPG in NSW	New	Transport	Gippsland	Sized to market requirements	
NGP mid-line compression	Compression at NGP mid-line	New	Transport	Northern Zone	130TJ/d (1 compressor), potential for further expansion via looping and/or compression depending on market needs	
NGP Beetaloo lateral	New pipeline from Beetaloo to the NGP	New	Transport	Northern Zone	130TJ/d or larger depending on market needs, potential for further expansion via looping and/or compression	

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QGP expansion North	Expansion North, from Wallumbilla to Gladstone	New	Transport	Gladstone	10 – 120 TJ/d, Sized to market requirements via looping and/or compression
QGP expansion South	Expansion South, to Gladstone	New	Transport	Northern Zone	Sized to market requirements via looping and/or compression
QGP Compression onto SWQP	New compression at Wallumbilla to enable firm deliveries onto SWQP	New	Transport	Northern Zone	Sized to market requirements
QGP – DDP Interconnection	Bi-directional connection between DDP and QGP	New	Transport	Northern Zone	Sized to market requirements