Draft 2025 Gas Infrastructure Options Report:

Response from the 2026 Integrated System Plan (ISP) Consumer Panel

June 2025

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Acknowledgement of country

The 2026 Integrated System Plan Consumer Panel acknowledges the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

Executive Summary

The GHD – "Gas Infrastructure Cost Building Block costs for gas infrastructure" [1] report that was released with the Gas Infrastructure Options (GIO) draft report deals with the costs of the gas infrastructure component and provides a comprehensive analysis of the risk factors that could increase or decrease the specific project costs.

<u>Uncertainty about future Investor behaviour</u>

However, investors in new gas infrastructure are not likely to only focus on costs, and the risk of cost 'blowouts' – particularly in the absence of government support/policy. These investors will also consider the revenue opportunities and the risks to this revenue in a competitive wholesale market.

<u>Future of gas and ISP application.</u>

It is not clear to the Panel how the GIO report anticipates the gas market to evolve.

The Draft GIO report would be enhanced by explicitly considering the following questions about future gas use:

- Will GPG act to 'firm' electricity supply during periods of high electricity demand and/or supply interruptions including periods of low level of renewable generation such as occurred in recent solar/wind/hydro 'droughts'.?
- Will GPG be more limited to operating as an emergency 'back up' supply for meeting short intraday peak periods very short period?
- Will GPG provide other frequency control and ancillary services to the electricity market,
- Will the role of GPG in the electricity supply market change over the ISP period to 2050, and if so, how?

Importantly too, how will GPG interact with grid scale batteries to provide firming and storage.

<u>Cost escalation</u>
In applying a single set of cost escalation indices for gas infrastructure components across all ISP scenarios, the Panel accepts the current approach of applying a single set of cost escalation indices for gas infrastructure components across all ISP scenarios in the 2026 ISP, recognising that the quality of the data at this point in time, does not warrant further refinement of the cost analyses.

We consider that this gap should be addressed in the 2028 ISP.

[1] FINAL - Gas Infrastructure Cost Report.docx

The cost escalation approach does not take adequate account of the changing role of gas and GHG in the electricity supply mix between now and 2050, and how this changing role may impact on the location, size and cost of different gas infrastructure options.

Additional Costings

One element of GHD's report that the Panel strongly supports is the inclusion of the following costs that are not part of the transmission cost data base: (GHD report, p 63)

- Yearly operating costs
- Cost of capacity upgrade
- Cost of refurbishment
- Decommissioning cost for natural gas

The Panel's support for the inclusion of these costs reflects our view that an important consideration for AEMO is to develop options that maximise the use of existing gas infrastructure. This has the potential to reduce costs to consumers by limiting the risks and costs of stranded or under-utilised existing gas transmission assets.

Sensitivity testing

At a minimum the GPG supply/demand forecasts should undertake sensitivity testing of the gas infrastructure options to variations in industrial demand for gas.

Consumer Risk

The simplified model of applying a single set of cost indices increases the risk of the gas infrastructure options analysis either overstating or understating the need for new investment in gas infrastructure. Either way, there will be a cost to consumers who ultimately carry the risk.

Overview

The Panel appreciates the opportunity to respond to AEMO's 2025 Draft Gas Infrastructure Options Report (Draft GIO report) published in May 2025.

This draft report is an important input into the 2026 ISP process and is the first time that AEMO has assessed in some detail the gas infrastructure requirements to support its analysis of the electricity supply options through to 2050.

As noted by AEMO, the Draft GIO Report builds, inter alia, on the Governments review of the ISP, and on AEMO's 2025 GSOO and the Draft 2025 ISP Methodology Report. Before responding in detail to the current Draft GIO report, the Panel has further considered the requirements on AEMO arising from the Government's review, and on our own response to the Draft 2025 ISP Methodology Report.

In particular, as set out below, the Panel is considering AEMO's Draft GIO report in the context of the expectations set out in the Government's review, the Energy Ministers' response to the review and the subsequent amendments by the AEMC to the Natural Gas Rules and to our expectations of impacts on consumers

ISP Review

The Federal Government's review and Energy Ministers' response re the ISP and gas infrastructure requirements to meet the ISP objectives.

The extension of the integration of gas infrastructure into the 2026 ISP was promoted in the first instance by the Federal Governments review of the ISP, The Energy Ministers' endorsed 15 of the recommendations of the review, concluding that:

"These changes will set a direction for the transformation across the energy system as a whole while maintaining the critical function of the ISP in [electricity] transmission planning."

(https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan)

In responding to AEMO's Draft GIO Report, the Panel will consider the following important matters raised by the Energy Ministers. Importantly, the Ministers' response included a recognition of the changing role of gas during the transition process:

"However, the role of gas-fired power generation (GPG) within Australia's energy mix is shifting from responding to daily fluctuations in power demand to a strategic backup role for renewable power generation. GPG will need to play a critical firming role alongside electricity storage, particularly during winter, to maintain grid stability amid the intermittency of renewable energy sources. Increasing electrification rates across households, businesses and industry are also expected to drive change in the gas sector." (p 6)

The Ministers highlighted the impact of the changing role of GPG on the profile of demand. While overall gas demand may decline, the prospect of 'significant peaks' in demand for gas will result in changes to how gas infrastructure is developed and used, a trend exacerbated by the forecast decline in supply from southern gas fields and greater reliance from other east coast gas sources. The Ministers concluded that:

> *"Given these significant drivers, it is critical that the ISP consider the changing dynamics in the gas market to better consider the full range of costs and operational limitations important to determining the role that gas may play in supporting the energy transformation. This should include* ***a more detailed view on the full cost of GSP relative to other forms of generation and energy storage****." (p 6) [emphasis added]*

The Ministers' response noted changes to the National Gas Rules made in early 2024 to incorporate natural gas, hydrogen and biomethane in AEMO's consideration of gas infrastructure requirements to meet the ISP's optimal development path (s). The Ministers promoted further changes to the NGR to support the proposed changes to the ISP. The AEMC published its final determination in December 2024 that required AEMO to include gas development projections in the ISP.

The Panel's response to the current Draft GIO Report considers the intent of the Ministers and the AEMC to enhance the integration of gas into the ISP.

AEMO is to be congratulated on the work it has undertaken to address the ISP gas integration matters raised by the Ministers.

However, as we discuss below, the Panel would prefer AEMO to have more explicitly considered the broader context of gas supply and infrastructure for GPG over the course of the electricity transition process.

Absent this assessment, there is a heightened risk of promoting over or under investment in GPG and the supporting gas supply infrastructure. Ultimately, consumers wear much of the costs of over or under investment.

Similarly, an exclusive focus on costs does not reflect the actual drivers of investment in 'flexible' gas. Investors in the gas market and GPG need confidence that the market will allow a fair recovery of these costs. For example, we argue below that large batteries will increasingly replace much of the shorter (intra-day) role that GPG has historically played. GPG will increasingly be used to address coincident shortages in renewable electricity supplies, and/or significant transmission constraints.

We further discuss these issues in the section below before responding to the specific questions raised by AEMO in its report.

The ISP and the ("East Coast") gas market

The ISP provides the framework for the transition of the east coast electricity market to renewables and ultimately to contribute to the objective of net-zero emissions by 2050. Gas fired power generation (GPG) is widely (albeit not universally) recognised as making a significant contribution to achieving that end. However, there remains considerable dispute over its role in the transition process across the ISP planning horizon.

The current GIO report provides a starting point for analysing the contribution that GPG can make to facilitating the transition process of the electricity supply market. As the Rules state, and AEMO acknowledges, the current report is directed at defining the feasible options for GPG to contribute to the least cost solution of the electricity transition. It is not intended to optimise the gas market. The Panel highlights the importance of this focus. There are many contemporary debates about aspects of gas markets in Australia, for domestic and export applications. The ISP interest in gas is however limited to considering gas a fuel for electricity generation for 'firming' purposes.

Nevertheless, any analysis of the GPG options must start with an understanding of the potential evolution of the electricity market as it moves towards net-zero, while minimising costs to the community and while meeting the legislated carbon budgets and temperature rise limits.

There is increasing awareness of the complexity of the electricity transition process. The 2024 ISP overview statement,

"With coal retiring, renewable energy connected with transmission and distribution, firmed with storage and backed up by gas-powered generation is the lowest-cost way to supply electricity to homes and businesses as Australia transitions to a net zero economy." (Page 6)

is a useful heuristic but does not directly address the evolving interaction between renewable energy, transmission expansion, (grid scale) battery storage, (pumped) hydro storage, CER/DER opportunities and gas supply/demand (including non-natural gas) – an evolution made more complex by the various policy changes and emerging social licence issues. For example, the Federal Government Capacity Investment Scheme[2], provides subsidies for commercial level battery investments, but not for proposals to expand investment in gas transmission and storage, an issue that is discussed further below.

In addition, the focus of the GHD – "Gas Infrastructure Cost Building Block costs for gas infrastructure" [3] report that was released with the GIO draft report and (it appears) the selection by AEMO of 'feasible options', is on the costs of the gas infrastructure components. Indeed, the GHD report provides a comprehensive analysis of the risk factors that could increase or decrease the specific project costs. (GHD report, p 61)

However, investors in new gas infrastructure are not likely to only focus on costs, and the risk of cost 'blowouts' – particularly in the absence of government support/policy. These

[2] Website is [Capacity Investment Scheme - DCCEEW]
[3] [FINAL - Gas Infrastructure Cost Report.docx]

investors will also consider the revenue opportunities and the risks to this revenue in a competitive wholesale market.

More specifically, it is not clear to the Panel how the GIO report anticipates the gas market to evolve. We explore this further in Appendix 1.

There are forecasts of gas demand for residential, commercial and industrial markets and a range of forecasts for GPG. However, GPG can also serve a limited number of functions/services in the future electricity market. We believe the Draft GIO report would be enhanced by explicitly considering the following questions:

- Will GPG act to 'firm' electricity supply during periods of high electricity demand and/or supply interruptions including periods of low level of renewable generation such as occurred in recent solar/wind/hydro 'droughts'.?
- Will GPG be more limited to operating as an emergency 'back up' supply for meeting short intraday peak periods over a very short period?
- Will GPG provide other frequency control and ancillary services to the electricity market, eg inertia?
- Will the role of GPG in the electricity supply market change over the ISP period to 2050, and if so, how?
- How will GPG interact with grid scale batteries to provide firming and storage.

These different roles will have very different impacts on gas supply and infrastructure requirements and the types of investors and their expectations for returns on their investment commensurate to the respective financial risks.

Notably, as an emergency supply, including the provision of FCAS, gas now competes with grid scale batteries that can respond more quickly to short-term interruptions to supply. Large scale batteries also have the potential to undercut some of the traditionally high-priced gas FCAS offers that occurred prior to the expansion of the battery market (for example, see the impact of the Tesla "big battery" in SA on FCAS prices that were previously set by the SA gas generators).

Supported by the Capacity Investment Scheme, the next decade is likely to see further growth in the size and numbers of market scale batteries, particularly in conjunction with renewable energy projects. For example, in the February 2025 half yearly presentation, Origin Energy's CEO reflected as follows[4]*:*

- Origin had invested in 700MW/2,800MWh Eraring battery and 300 MW/MWh Mortlake battery in Victoria next to its gas generator
- battery storage costs have fallen sharply and continue to fall, and Origin expects to see batteries playing a key role in quick response to market price moves and short-term supply needs.

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[4] *Note: sourced from Renew Economy, 13 February 2025, https://reneweconomy.com.au/origin-eyes-wind-solar-batteries-and-new-gas-plants-as-higher-cost-of-coal-clips-energy-earnings/*

- Origin is currently considering new investments in ‘mid-merit’ gas generators at Mortlake, Darling Downs and in NSW.

Response to AEMO’s consultation questions

Note that the questions from the draft report are copied in italics and considered in the order presented in the draft report.

1. *Do you have any feedback on the gas infrastructure base costs, adjustment factors and escalation indices provided by GHD?*

<u>Base Case</u>

GHD has been commissioner by AEMO to develop “building block costs for gas infrastructure’[5] and this report has been published with the GIO Report, Our reference to GHD refer to this report. In large part, GHD has estimated its base costs using extrapolation of historical cost data provided by the industry. The data is considered at a ‘category’ level (e.g., natural gas, biomethane etc), and at ‘sub-category’ level (e.g., ‘production costs, underground pipeline costs etc).

It also takes account of the expected capacity of production or transport or storage with the ‘base cost’ (excluding adjustment factors) being the multiple of the unit rates determined by the capacity expected. Specifically, GHD proposes that the base rates be scaled to reflect reductions in base case unit rates for assets over a certain capacity. (see GHD report, p 62).

The Panel considers this is a reasonable starting point for estimating the base costs, noting the further adjustments to these base costs for ‘project unique attributes’, as described below.

However, we note that the cost forecast estimates derived from the statistical analysis of historical data reveals a high standard error in the forecast for most cost elements (see GHD report, Figures 3-10, pp 55-57). As a result, the forecast cost elements are categorised as Class 5 under the Association for the Advancement of Cost Engineering (AACE International) framework. These wide margins in cost estimates do not give consumers confidence in most publicly quoted cost estimates.

<u>Adjustment Factors</u>

GHG uses the ‘adjustment factors’ to increase or decrease their ‘initial’ estimate of project costs. These are in addition to what GHG identifies as ‘risk factors’ which are used to increase or decrease project costs to allow for project specific risks (GHG report, p 61)

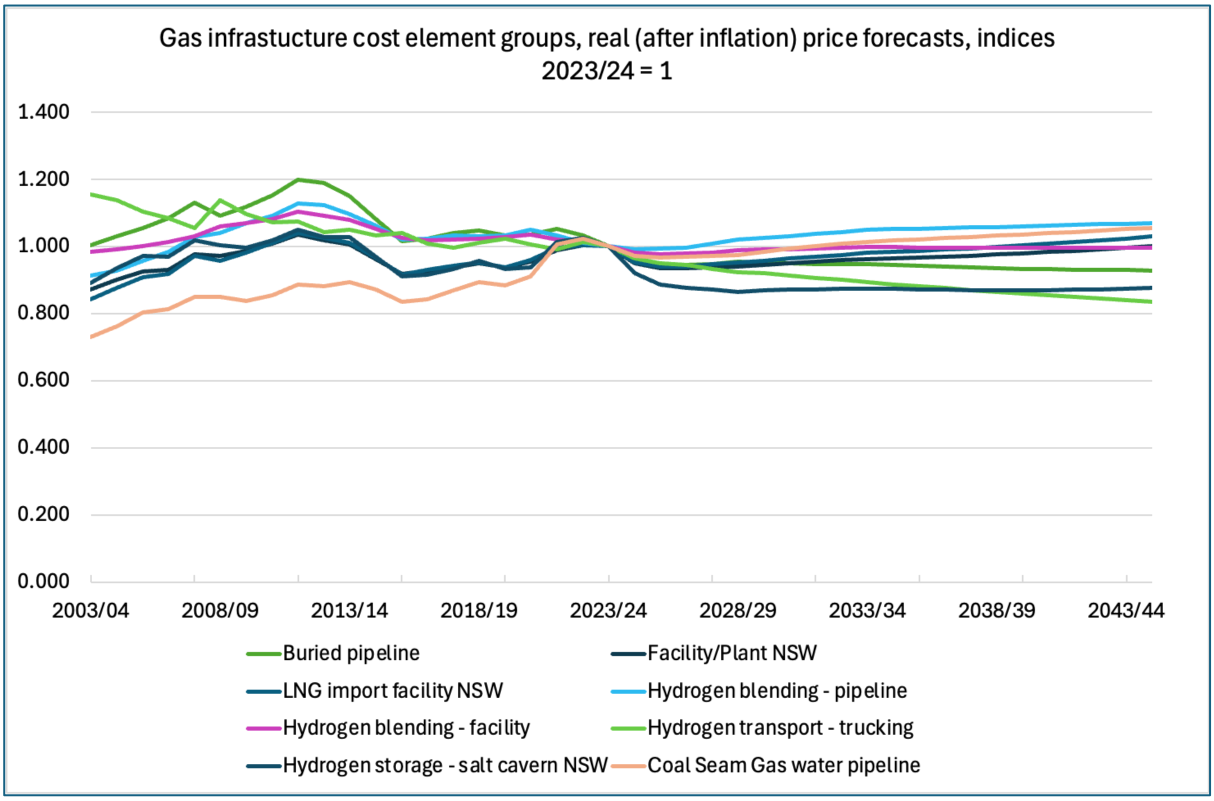
[5] FINAL - Gas Infrastructure Cost Report.docx

GHG identifies five adjustment factors: terrain, location, length, diameter and a final scaling factor. (GHG report, p 60)

Escalation indices

GHD provides a detailed breakdown of both nominal and real cost indices, with a base year of 2023/24, historical 'actuals' back to 2003/04 and forecast through to 2043/44

The chart below summarises the real cost indices for specific cost infrastructure, with the element costs built up from forecast of changes in component costs (weighted for each element).



While the historical indices show significant volatility, the forecasts present a relatively stable view of real costs at the element group level, with some elements (such as 'buried pipeline') reducing in real cost terms over the forecast period.

We understand that this relatively benign cost forecast – a contrast to the substantial cost increases forecast for electricity infrastructure – reflects the view that gas supply is a mature industry and gas infrastructure does not face the same world-wide supply challenges facing, for example, electricity transmission builds. In addition, overall gas demand is expected to decline over the forecast period.

However, the Panel remains concerned that the forecast gas infrastructure cost indices may not adequately reflect the changing role of natural gas and GPG in the electricity market across the transition period, nor reflect the shorter term volatility in prices as the recent past has demonstrated.

For example, if GPG is principally required to address short-term peak supply issues, then the options selected by AEMO may focus on promoting gas storage located close to a GPG plant. This may allow a smaller diameter pipeline (or use of existing gas transmission lines) from upstream sources to storage. On the other hand, costs per MJ delivered may increase, reflecting for example, the higher per unit cost of production.

If the outlook is for GPG to provide longer duration firming support to the system, then the optimal mix of storage and pipeline capacity may be different, as may the contractual requirements with upstream suppliers.

These different outcomes impact directly on the overall costs of the proposed options, and indirectly, through different contractual arrangements with upstream suppliers. These uncertainties can then flow through to high costs for consumers, in a cost environment in which 'cost of living' pressures are high and the relative costs fo energy increasing substantially.

2. *Do you have any feedback on the methodology for the gas infrastructure base costs and forecasts provided by GHD?*

The comments provided above, in response to question 1 also apply to this question.

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? Gas development projections*

The Panel recognises both the importance and complexity of the new requirement to consider gas infrastructure options in the context of the ISP (an outcome of the 2023/24 ISP review conducted through DCCEEW). We also recognise that the quality of the data at this point in time, does not warrant further refinement of the cost analyses.

For this reason, we accept the current approach of applying a single set of cost escalation indices for gas infrastructure components across all ISP scenarios in the 2026 ISP.

However, we do consider this gap should be addressed in the 2028 ISP. For example, the level, and percentage, of displacement of natural gas by hydrogen for industrial use varies considerably between the progressive scenario and the two green energy scenarios. This, in turn, impacts on the demand for new gas infrastructure and therefore the overall cost of gas supply to GPG.

In addition, GHD's analysis identified correlations between various economic indicators and the costs of various inputs. For example, the GHD report identifies correlations between plastic piping and economic variables relevant to the scenarios as follows (GHD, p 52):

"Plastic piping is positively correlated to the inverse of the unemployment rate, unit labour costs and import prices"

The simplified model of applying a single set of cost indices therefore increases the risk of the gas infrastructure options analysis either overstating or understating the need for new investment in gas infrastructure. Either way, there will be a cost to consumers who ultimately carry the risk.

4. Do you have any feedback on AEMO's use of GHD's component costs in costing gas infrastructure options?

The Panel considers the GHD report to be an important first step towards an assessment of gas infrastructure options. In principle, therefore, AEMO's use of GHD's component reflects this 'first step' in the analysis of the options.

However, as explained above, the Panel is concerned that the cost-based approach in the GHD report relies to a substantial degree on trends in historical data. The approach does not take adequate account of the changing role of gas and GHG in the electricity supply mix between now and 2050, and how this changing role may impact on the location, size and cost of different gas infrastructure options.

Nor do the component costs reflect the alternative scenarios that are fundamental to the ISP forecasting approach.

One element of GHD's report that the Panel strongly supports is the inclusion of the following costs that are not part of the transmission cost data base: (GHD report, p 63)

- Yearly operating costs
- Cost of capacity upgrade
- Cost of refurbishment
- Decommissioning cost for natural gas

The Panel's support for the inclusion of these costs reflects our view that an important consideration for AEMO is to develop options that maximise the use of existing gas infrastructure. This has the potential to reduce costs to consumers by limiting the risks and costs of stranded or under-utilised existing gas transmission assets. Residential and business consumers already face the costs of stranded gas distribution assets, so maximising the use of existing transmission assets (as overall gas demand declines) should be a critical factor in AEMO's selection of 'plausible' options.

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?

2C resources are defined internationally by the Petroleum Resources Management System as the best estimate of 'contingent' resources, that is, a 2C resource is the most likely or best estimate of the quantity of gas that could be recovered from a particular gas resource location.

The Panel therefore supports AEMO's proposal to limit sources of new natural gas supply to known 2C resources based on information from both the Gas Bulletin Board (Gas BB) and GSOO surveys.

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? Application of gas development projections for fuel limitations in the ISP*

Appendix A2 sets out a comprehensive list of the options that may be used in the gas development model that includes options for production, storage, transport and regasification (for LNG projects), along with the relevant zone and capacity.

The Panel commends AEMO for its work in identifying these options. However, the Panel cannot comment at this stage on whether the list is comprehensive and the options meet the relevant standard of 'plausibility'.

We reiterate our more general concern that the options are being identified as 'plausible' without consideration of the context for review of gas options in the 2026 ISP, namely to identify the future role of natural gas (including LPG) and GPG in the transition of the electricity market.

7. *Will AEMO's proposed gas supply and pipeline zone limitations be effective in limiting fuel availability for GPG?*

AEMO states in the GIO report (p 26) that rather than applying daily gas fuel limits for each individual generator, it intends to calculate daily supply limits for the 13 gas supply or pipeline zones. In this approach, the daily gas fuel limit is the total gas supply available to all GPG in a given zone after taking account of the residential, commercial and industrial gas demand in each zone.

AEMO's 'zonal' approach to assessing pipeline limitations provides a practical means of assessing 'plausible' options. It allows AEMO to identify and model potential new GPG development locations subject to recognition of the constraints to gas supply in that region.

The process of establishing limits based on existing, committed or anticipated projects allows the model to eliminate options that require more expensive expansions to the existing gas transmission system (ie, non-plausible options) or to identify opportunities for future capacity investments.

The Panel considers using the zonal approach rather than the complex task of considering each generator, is reasonable in the context of the ISP requirements and that it likely helps to reduce further future cost risks for consumers.

8. *Considering the purpose of the assessment, is it reasonable to apply priority to residential, commercial and industrial customers ahead of GPG?*

The Panel considers there are arguments for and against this approach. Overall, however, the approach of allocating gas supplies and infrastructure first to meet the forecast residential and commercial and industrial customers ahead of GPG is reasonable at this stage in the development of the gas supply model.

We note here that the current forecasts of declining gas demand in the residential and commercial markets are fundamental to this approach as it notionally 'frees up' existing gas transmission capacity for GPG. Maximising the use of existing capacity for GPG is clearly preferable to building new gas transmission specifically for GPG particularly given the high risk of underutilised capacity in a new GPG driven pipeline.

An important caveat to this, is the uncertainty around the future of natural gas in the industrial sector. Currently there is no economic substitute for natural gas in many large-scale industrial processes, particularly processes that require secure year- round supplies of gas. However, the task of meeting net-zero by 2050 (and the interim carbon budget targets) will continue to drive research on 'green energy' solutions including green hydrogen and high temperature heat 'storage'.

At a minimum therefore, the GPG supply/demand forecasts should undertake sensitivity testing of the gas infrastructure options to variations in industrial demand for gas.

9 *Are there any supply zones missing? Are there any supply zones that will be unrealistically represented by the proposed constraints to gas supply?*

The Panel is not in a position to respond to this question at this stage in the process.

Appendix 1. Scenarios for Future Gas Market

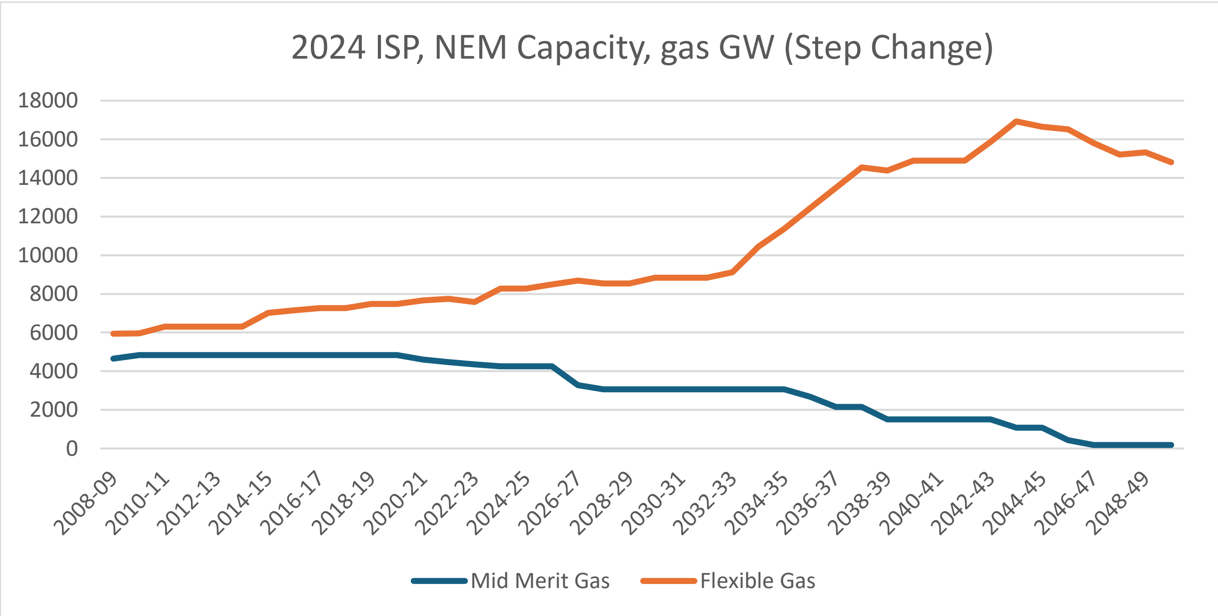
On page 6 we observe "… it is not clear to the Panel how the GIO report anticipates the gas market to evolve."

The Panel recognises the active debates that are currently underway in Australia (and around the world about the 'future of gas' with regulated gas networks increasingly seeking accelerated depreciation to reduce the risk to businesses of holding stranded assets while considerable discussion surrounds the potential for 'renewable' gas, specifically hydrogen produced from electrolysis and 'biogas.'

The ISP and the gas market

The ISP provides the framework for the transition of the east coast electricity market to renewables and ultimately to contribute to the objective of net-zero emissions by 2050. Gas fired power generation (GPG) is widely (albeit not universally) recognised as making a significant contribution to achieving that end. However, there remains considerable dispute over its role in the transition process across the ISP planning horizon.

This is reflected in the final 2024 ISP that included the following data in chart 2 relating to the role of gas in NEM electricity capacity to 2050. We note that while the role for 'mid merit gas' diminishes, the capacity from 'flexible gas' increases from current levels with material increases on the early-mid 2030s as coal generation declines. The role of gas is modelled to start diminishing from the mid 2040's. We note that by the mid 2040's the capacity of gas is about 10% of CER, but its firming role remains significant under current modelling.



Source: 2025 ISP chart 2

The current GIO report provides a starting point for analysing the contribution that GPG can make to facilitating the transition process of the electricity supply market. As the Rules state, and AEMO acknowledges, the current report is directed at defining the feasible options for GPG to contribute to the least cost solution of the electricity transition. It is not intended to optimise the gas market. The Panel highlights the importance of this focus. There are many contemporary debated about aspects of gas markets in Australia, for domestic and export applications. The ISP interest in gas is as a fuel for electricity generation for 'firming' purposes.

This leads us to consider Scenarios of future of gas for GFG and we have identified 4 main options, though there are others:

1) Existing infrastructure is likely fine to 2050, so only marginal costs need to be applied to maintain the network and supply.
2) Gas demand falls significantly across business, commercial and household sectors, so gas providers need to be compensated to retain operability
3) More gas capacity is needed to meet GFG requirements eg onsite gas storage for GFG generators
4) Different gas; Biomethane, hydrogen. If hydrogen, then there are conversion costs.

So likely gas demand for GFG will be required to:

1. Meet occasional short time period daily peaks (a couple of hours), eg for air conditioning in summer
2. Extended Blocks of generation (over many days) to meet 'renewable drought events, eg dunkelflaute,

Which begs the question of how much gas will be needed, when and for how long? In other words, how 'flexible' can 'flexible gas' be? This is our thinking behind the statement "… it is not clear to the Panel how the GIO report anticipates the gas market to evolve." This is a crucial matter that underpins GIO considerations