Australian Gas Infrastructure Group

**30 October 2025**

Australian Energy Markets Commission (AEMC)
via online submission

Dear Commissioners,

**"Gas Networks in Transition" Consultation Paper GRC0082**

Australian Gas Infrastructure Group (AGIG) welcomes the opportunity to provide this submission to the Australian Energy Market Commission (AEMC) in response to its "Gas Networks in Transition" consultation paper. Through our ownership of Australian Gas Networks (AGN), Multinet Gas Networks (MGN) and the Dampier to Bunbury Pipeline (DBP), AGIG delivers energy to more than two million customers, operates extensive gas distribution, transmission and storage infrastructure, while actively pursuing renewable gas production, carbon pipeline and carbon capture and storage (CCS) projects across Australia.

We support the AEMC's commitment to ensuring the National Gas Rules (NGR) remain fit for purpose and be adaptively applied through the transition to net zero. Through our *Net Zero Ambition*, we are advancing a clear pathway to achieve net zero in our own operations and to enable it for our customers, working collaboratively with governments, industry and research organisations to achieve our Vision of delivering infrastructure essential to a sustainable energy future.

The consultation addresses a series of proposals from Energy Consumers Australia and the Justice and Equity Centre (the proponents) that, if implemented, would substantially alter the economic regulatory framework governing gas networks. Our response demonstrates how the underlying economic problem has been mischaracterised by the rule change proponents, how several elements appear contrary to, or outside the intent and scope of the NGL, and how the proposed amendments would risk undermining a stable, proven framework that continues to efficiently serve both customers and investors in essential energy infrastructure.

## Transition is uncertain for all, but risks are manageable

The transition to net zero presents significant uncertainty for all energy sectors, including gas. While it is widely accepted that gas will continue to play a role in the transition to net zero and beyond, demand trajectories, technology pathways, and policy settings are evolving rapidly, with different jurisdictions pursuing distinct pathways and timeframes to achieve their emissions reduction goals. This approach aligns with the Australian Government's *Future Gas Strategy*, which confirms that natural gas and its infrastructure is needed through to 2050 and beyond under all credible net zero scenarios. While these uncertainties present real challenges, they remain under most circumstances manageable within the existing regulatory arrangements.

The NGL and NGR already provide the flexibility necessary to address these challenges. The existing depreciation and revenue-setting mechanisms, when used correctly, give regulators effective tools to respond to changing market conditions while maintaining consumer protection and investor confidence. Stable and predictable regulation ultimately benefits consumers by keeping financing costs low, supporting reliable service delivery and enabling competition and innovation in renewable gases to emerge efficiently.

## Proponents mischaracterise the underlying issue

Discussion around the future role of gas has taken on a higher profile in recent years, but in practice, Australia's gas infrastructure has evolved alongside customers' needs for generations. Australia's gas distribution and transmission networks are still undergoing this continued evolution as the nations' energy mix changes. The key challenge is not whether the existing regulatory framework can manage declining demand but whether regulatory stability can be maintained as networks adapt to new technologies, including renewable gases such as hydrogen and biomethane.

Importantly, the issue faced by networks concerns economic asset stranding not physical asset stranding as characterised by the proponents. This distinction is critical because regulation manages financial risk, not engineering failure. Confusing the two leads to measures that address the wrong problem.

Economic asset stranding occurs when market or policy changes mean the price at which services produced by a network cannot fully support the Regulated Asset Base (RAB) which has been invested to provide those services. Physical stranding, by contrast, refers to assets that have failed, become obsolete, or are no longer required for service. The NGL and NGR were explicitly designed to manage economic asset stranding risk through mechanisms such as depreciation flexibility under Rule 89, ensuring networks retain a reasonable opportunity to recover efficient costs while adapting to market conditions.

## Proposed changes do not contribute to the achievement of the National Gas Objective and undermine the existing regulatory framework

The proposed changes would fundamentally depart from the intent of the NGL, the achievement of the National Gas Objective (NGO) and the Revenue Pricing Principles (RPP).

The AEMC may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NGO. The proposed rule changes, if introduced, would have the effect of undermining efficient investment and not be in the long-term interests of consumers. We do not consider the proposed changes meet the threshold test.

The AEMC must also have regard to the RPP in considering a rule change. These principles ensure that service providers have a reasonable opportunity to recover efficiently invested capital while promoting efficient investment and consumer protection. The proposed changes would erode these foundations by introducing provisions inconsistent with both the NGL and the established role of the regulator.

Requiring or enabling regulators to write down the value of efficient investments based on a forecast of future use that may or may not eventuate contradicts the principle of reasonable opportunity for cost recovery and undermines the regulatory compact that underpins long-term investment in essential infrastructure. Such measures would crystallise potential future losses, weaken investor confidence, and shift the risk allocation embedded in the NGL. They would also signal to investors across other regulated sectors that the value of approved investments may be revisited through regulatory discretion, increasing perceived sovereign risk.

Stable, predictable regulation is essential to promote efficient investment in the long-term interest of consumers. Consumers ultimately bear the cost of inefficient regulation: when investment is discouraged, service quality and reliability decline, and costs rise over time. Such outcomes would be contrary to the long-term interests of consumers. The current framework, in comparison, aligns investor incentives with consumer outcomes, ensuring networks continue to provide safe, reliable and affordable services. Included with our response is a brief expert report from Incenta Economics, which affirms these points and outlines how the NGR and the flexibility it provides through depreciation were developed with these principles in mind.

## The current framework is proven and adaptable

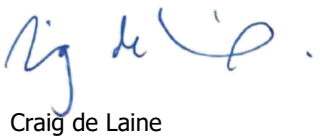
The existing building block model has been tested and refined through successive access arrangement determinations across both gas and electricity networks. It is a proven and flexible framework that promotes efficient investment and safeguards consumer interests. Maintaining a stable and predictable framework will continue to support investment in safe, reliable and affordable energy services while enabling the orderly integration of renewable gases such as hydrogen and biomethane.

International regulatory practice reinforces this approach. Comparable jurisdictions, including the United Kingdom, manage transition risks through measured regulatory discretion and flexible depreciation. These regimes continue to uphold the principle that networks should have a reasonable opportunity to recover efficient costs over the life of their assets, recognising this as fundamental to maintaining investor confidence and long-term affordability for consumers.

The NGL and NGR already achieve the objectives sought by the proponents through balanced risk allocation and consumer protection. The proposed amendments would instead weaken investment incentives and reduce the stability necessary for an orderly energy transition. We recommend the AEMC maintain the current framework, with only limited clarifications where required. This approach will sustain investor confidence and ensure that regulatory arrangements continue to serve the long-term interests of consumers.

The attached submission expands on these points, drawing on regulatory case studies and international evidence to demonstrate how the existing framework continues to balance consumer protection and efficient investment through the transition. If you have any questions regarding this submission or would like to discuss AGIG's views in more detail, please contact Owen Sharpe, Strategy and Policy Manager, at owen.sharpe@agig.com.au.

Kind regards,



Craig de Laine
Chief Executive Officer

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| **Q1 – Issues and Scope** | **1. What are the issues impacting consumers and gas distributors under the energy transition**<br><br>The transition to net zero presents significant uncertainty for all energy sectors, including gas. While it is widely accepted that gas will play a role in both the transition to net zero and the net zero economy post transition, demand trajectories, technology pathways, and policy settings are evolving rapidly, with different jurisdictions pursuing distinct pathways and timeframes to achieve their emissions reduction goals. While these uncertainties present real challenges, they remain manageable within the existing framework of building block regulation, with only minor amendments required.<br><br>The proposed rule changes have sought to address the issue of physical asset stranding, which they imply will result in risk being unfairly distributed to consumers, as demand for gas networks declines. This fundamentally mischaracterises the issue facing gas networks and their customers, which is the risk of *economic* asset stranding. The Australian Energy Regulator's (AER) 2021 Information Paper, *Regulating Gas Pipelines Under Uncertainty* (the 2021 Information Paper)[i] is an important resource for understanding the issues impacting consumers, gas distributors and regulators.<br><br>The 2021 Information Paper links the challenges associated with economic asset stranding to the tools available under the building block regulatory model to manage risk. More specifically, the 2021 Information Paper defines stranded assets as '*investments that are no longer able to earn an economic return prior to the end of their economic life*'.[ii]<br><br>The paper further notes *economic* asset stranding *'is caused by a change in relative costs or prices' and 'is distinct from physical stranding, which refers to an asset that ceases to be used because of reasons such as obsolescence, failure, damage etc.'*[iii]<br><br>The AER goes on to describe the implications if economic asset stranding is unmanaged:<br><br>> *'If the constraints on gas prices become sufficiently strong such that gas becomes relatively uncompetitive, then with falling demand, regulated revenues for regulated businesses may not support full cost recovery of the RAB [Regulated Asset Base]. In this scenario, the network business will under-recover the amounts it has invested over the life of its assets, including a normal rate of return on those capital investments.*[iv]<br><br>Economic asset stranding occurs when the price formed by the regulatory building block model fails to bind the energy network – that is, when external market pressures compel the network to set a lower price to remain commercially viable. The portion of assets that become 'stranded' represent the value which cannot be recovered under these lower prices. In this situation, the regulator can no longer uphold its side of the regulatory compact, that is ensuring investors have a reasonable opportunity to recover their capital, as the model no longer produces prices charged by the business. In this circumstance, adjustments to depreciation schedules need to be applied to mitigate this risk.<br><br>As the relative price of gas increases – due to increased competition, declining demand, policy shifts or a combination thereof – networks must adopt tariffs that remain competitive with alternative energy sources. To maintain a reasonable opportunity for networks to recover efficient investment costs and a return commensurate with the associated regulatory and commercial risks, the building block framework should continue to be the mechanism used to manage the risk of economic asset stranding.<br><br>This is a key question for consumers and gas distributors in the energy transition: whether the risk of economic asset stranding can continue to be managed within the framework established under the National Gas Law (NGL), detailed in the NGR and implemented by the AER and the Economic Regulatory Authority (ERA).<br><br>Across multiple Access Arrangement (AA) proposals and decisions by both the AER and ERA, this framework has demonstrated its capacity to manage the risks associated with economic asset stranding effectively. Our responses to questions 4, 5 and 6, and detailed discussion in Attachment 1 provide examples of how the NGL/NGR framework has been applied in regulatory practice and explain why it should be retained with only minor amendments.<br><br>In contrast to this understanding of the issues, the proposed rule changes focus on amendments to the NGR that seek to guarantee particular outcomes and, in doing so, would fundamentally alter the framework of building block regulation established under the NGL. The proposals incorrectly assume that any variation to economic asset lives automatically transfers risk to customers. In practice, economic lives are not static and varying depreciation is a long-established and effective mechanism for managing the risk of economic asset stranding that is reflected in the National Gas Rules (clause 89). |

The importance of retaining flexibility within the building block framework is reinforced by the broader context of Australia's energy transition. As outlined in Attachment 2 Section 1, the path towards net zero is categorised by uncertainty across jurisdictions, policy settings, and technological developments. This uncertainty requires regulatory flexibility, not prescriptive changes that remove discretion from regulators and service providers.

**1.1 Do stakeholders agree that there is value in considering the additional NGR issues we have identified alongside the issues raised in the rule change requests?**

We do not agree that there is value in the AEMC considering any further issues. We do not agree the AEMC should be considering the rule changes proposed given, at their core, they represent a fundamental and retrospective repurposing of the regulatory framework to the detriment of customers, the economy and gas infrastructure businesses, as well as a misunderstanding of the risks the industry faces.

While we acknowledge that *'the breadth of issues and potential solutions requires a more holistic assessment to determine whether changes to the regulatory framework are required'* that should not form part of this review[v]. We consider that the proposed rule changes do not fully recognise the interrelationships between depreciation, capital expenditure, and other components of the building block framework. A comprehensive understanding of the framework, and of the principles underpinning its adoption, supports the conclusion that only minor amendments may be necessary – not the wholesale change envisaged by the rule change proposals.

**1.2 Are there any other additional issues that we should consider within the NGR framework? If so, why?**

We do not presently consider there are 'additional issues' that warrant examination. As highlighted throughout this response, the proposed rule changes would constitute a significant departure from the framework established under the NGL, particularly the National Gas Objective (NGO) and the revenue and pricing principles. For the reasons we explain at Question 5, the proposed rule changes do not meet the threshold test of contributing to the achievement of the NGO. The issues identified in the consultation paper are sufficient to assess the effectiveness of the NGL/NGR framework in addressing the matters raised. Given the potential consequences of the proposed amendments, these should be carefully considered before any further changes are contemplated.

**1.3 Noting the AEMC's role is to consider and make changes to the energy rules, are there changes outside the NGR regulatory framework that are required to address the issues raised in the rule change requests?**

As noted above, the proposed rule changes would constitute a significant departure from the framework established under the NGL, particularly the NGO and revenue and pricing principles. There are no grounds for changing this broader framework in the NGL. The overarching goal of the NGO, ' to promote efficient investment in, and efficient operation and use of, covered gas services for the long-term interests of consumers', and the revenue and pricing principles (see Attachment 1 Section 3.3, and Question 4 below), are longstanding cornerstones of utility regulation in Australia and internationally. As highlighted at Attachment 1 Section 2.3.1, they are essential for maintaining investor confidence, including during the energy transition.

As outlined in Attachment 1 Section 2.3, the provisions within the NGR which govern depreciation and which were designed to be able to deal with the risk of economic asset stranding have been designed explicitly to work towards the NGO and RPP, delivering the objectives in the lowest cost way for consumers. A change to the NGL framework would introduce significant new risks for investors in regulated utilities across Australia. As demonstrated through international examples, the current tools available for addressing economic asset stranding are appropriate for the challenges of the energy transition. The NGL (and the NGR) is capable of appropriately addressing the risk of economic asset stranding without change.

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| **Q2 – Capital expenditure criteria (ECA)** | **2. What changes, if any, should be made to the NGR capital expenditure criteria?**<br><br>Changes to the NGR capital expenditure criteria are not necessary.[vi] The existing framework of building block regulation, and particularly the risk of economic asset stranding which comes from being unable to predict all forces which might drive future prices accurately, already imposes a strong internal discipline for network operators to ensure investment decisions are prudent and efficient. These arrangements create clear incentives to avoid expenditure that may not be recoverable.<br><br>In addition, the existing criteria provide regulators with ample discretion to determine whether proposed expenditure is efficient and in the long-term interests of consumers and to allow or disallow capital expenditure accordingly. This occurs twice – at the time forecasts are a accepted and when actual capital expenditure is included in the Regulated Asset Base. The most material source of risk – increased capital expenditure for connections being added to the RAB – is already being addressed through the AEMC's draft rule change on connections expenditure.[vii]<br><br>Together, these factors mean allowed capital investment has been, and will continue to be, efficient under the existing rules.<br><br>The risk of asset stranding itself provides a deterrent to excess capital expenditure. The AEMC consultation paper (p.15–16), notes the ECA's concerns that the capital expenditure criteria create *'irresistible incentives for networks to seek ever higher capital expenditure allowances'*, and that regulators should act to ensure that capital expenditure is deployed sparingly to protect customers. This concern misunderstands the incentives at play.<br><br>Capital investment is not guaranteed merely because a network is regulated. As the AEMC notes (AEMC consultation paper p.45), there is no guarantee that invested capital will be recovered, as economically stranded assets cannot be returned through regulation. Networks understand this, which ensures that proposed investments are prudent and sustainable under a range of demand and pricing scenarios (see detailed discussion of asset stranding in Attachment 1 Section 2); the future cannot be predicted with certainty so a prudent network takes this into account when planning capex, as it understands that there are circumstances nobody can predict, and which the regulatory framework cannot address.<br><br>It is important to note that capital expenditure and additional depreciation are not inconsistent. While the ECA suggests that proposing capital investment while seeking additional depreciation indicates a weakness in the current framework, this reflects a misunderstanding of how the framework manages investment and risk. Capital expenditure occurs for a variety of reasons and across assets with different lifespans, risk profiles, and regulatory drivers. For many asset categories, the potential for economic stranding is immaterial, meaning investment can proceed efficiently while depreciation adjustments are applied elsewhere to manage long-term risk.<br><br>Economic asset stranding, to the extent that it might happen, is a long-term risk driven by emerging market forces which are as yet unpredictable. In AGIG's recent South Australians (AGN SA's) Access Arrangement proposal, our best estimate of when regulatory prices may no longer bind is around 2050. Very few asset categories have lives extending to that point. For example, Information Technology (IT) assets typically have a five-year life and are entirely unaffected by potential stranding risks that might occur in the middle of the century. The same logic applies to most asset classes with lives shorter than 25 years.<br><br>Additionally, not all capital expenditure is within a networks' control. Networks are required to undertake certain capital expenditure projects to comply with safety requirements, and other explicit or implicit legal obligations. Some expenditure is growth-related as in most jurisdictions there are no restrictions on new connections, many customers continue to seek connection to gas.[viii]<br><br>In our recent AGN SA proposal, the total proposed capital expenditure for the five year period 2026/27 to 2030/31 of $503 million is roughly 10% below that incurred in the current Access Arrangement period. The forecast capital expenditure comprises of around:<br><br>• $160 million for new connections (which would not be included in the RAB under the AEMC's connection charge draft rule);<br>• $89 million required by the SA safety regulator to comply with safety cases; and<br>• $110 million for short-lived assets unaffected by potential stranding. |

| AGN SA Asset Category | Forecast Gross Capital Expenditure over the 1 July 2026 – 30 June 2031 AA period ($2025/26 million) |
|---|---|
| Mains | $135.4 |
| Inlets | $107.2 |
| Meters | $55.6 |
| Telemetry | $4.0 |
| IT System | $96.5 |
| Other Distribution Equipment | $96.3 |
| Other | $8.0 |
| **Total** | **$503.0** |

Of the $503 million forecast capital program, less than one-third, or around $142 million potentially falls within the scope of the proposed rule changes. The remainder comprising connections, safety and short-lived asset investments already managed under existing regulatory processes. This demonstrates that the framework is already addressing the key areas of investment efficiently and proportionately.

### Renewable Gas Capital Expenditure

The ECA's proposal to exclude expenditure on renewable gas adaption from the RAB further illustrate its inconsistency with both regulatory principles and efficient network design. If implemented, natural gas customers would fund all assets supporting natural gas services, while renewable gas customers would pay for the assets necessary to deliver renewable gases. This fragmentation would undermine the principle of shared network efficiency, substantially increase system-wide costs, and contradict the NGO by discouraging efficient investment in infrastructure capable of delivering covered gases[ix]

We also reject the ECA's assertion (AEMC consultation paper p.16) that networks are proposing capital expenditure to support the use of renewable gases *'despite electrification being a lower cost option to avoid natural gas emission'.* There is no conclusive evidence that electrification is the lower cost pathway for our diverse customer base, which spans metropolitan, regional and remote areas across six jurisdictions with differing climates and includes a wide range of residential, commercial and industrial users with diverse energy needs and socio-economic circumstances. Electrification has been available to customers since the establishment of AGIG's gas distribution networks more than 150 years ago, and gas networks have continued to grow sustainably alongside it. Refer Attachment 2 Section 3.1 for further discussion of AGIG's distribution network trends which shows that customer choices reflect a balance of reliability, upfront and lifecycle costs, appliance suitability, and energy preferences.

Over time, as renewable gases scale and costs decline, the comparative economics between energy options will continue to evolve; and the flexibility afforded by having different energy sources continues to deliver value. Attachment 2 Section 2.2.4 shows renewable hydrogen and biomethane costs are projected to fall within the same cost range as delivered natural gas by the mid-2030s. National policy frameworks reinforce this direction. The Future Gas Strategy (2024) affirms gas will remain part of Australia's energy mix, while the National Hydrogen Strategy (2024) highlights strong support for renewable gases through funding ($2 billion Hydrogen Headstart and $6.7 billion Hydrogen Production Tax Incentive), and the implementation of Guarantee of Origin certification frameworks. The Australian Government's recent Net Zero Plan outlined that *'renewable hydrogen and biomethane are expected to play an important role in Australia's long-term energy mix, with biomethane contributing earlier and hydrogen playing a larger role later'*[x], evidencing the Government's expectation for and commitment to continued renewable gas industry development.

Regardless, this is not a question for economic regulation. The role of the regulators is to ensure that network investments are prudent and efficient and that pricing outcomes protect customers from monopoly power. It is not within their remit to make policy decisions about preferred technologies.[xi]

**2.1 Are changes required to the current capital expenditure criteria to better account for uncertainty in future gas demand? If so, would ECA's proposed amendments better account for uncertain demand outlooks than the current criteria?**

Changes to the NGR capital expenditure criteria are not necessary and ECA's proposed amendments would not better account for demand uncertainty than the existing criteria. Networks must demonstrate that expenditure is justified – whether for safety, reliability, or service obligations – and that alternatives have been assessed. Regulators subject all proposals to rigorous review including by external subject matter experts, and often challenge the criteria being used to justify specific proposals. The regulators can and do disallow expenditure where the tests in rule 79 are not met. Each of the issues raised in the rule change proposal are adequately addressed by the existing criteria as outlined below.

### Gas distributors should explicitly consider the impacts of declining demand when proposing capital expenditure

Networks already incorporate demand forecasts when developing capital proposals. Our demand forecasts incorporate both total volume of gas to be transported through the network as well as the number of connections to the network. Attachment 2 Section 3.2.1 demonstrates that while average consumption per residential connection has moderately declined in recent years while commercial and industrial consumption remains steady, residential customer connections have continued to grow in accordance with historic trends, including in Victoria where policies interfere with customer choice to dissuade gas uptake.

As outlined in response to Question 2, networks have no guarantee that investments will be returned and accounting for demand uncertainty is integral to minimising stranding risk. Furthermore, as outlined above, long-term demand is not relevant for all capital investment decisions, specifically those where assets lives are relatively short. No change is required to explicitly consider the impacts of declining demand.

### Gas distributors should consider alternatives to investment

Gas distributors already consider alternatives to investment in every capital expenditure proposal. However, networks cannot be expected to assess the cost of entirely different energy services offered by other sectors. Nor should cost be viewed as the sole measure of value. Consumers place importance on flexibility, energy choice and reliability, all of which are central to efficient market outcomes and broader energy system resilience. The diversity outlined in Attachment 2 Section 3.2 shows that customers value these attributes differently depending on their location, circumstances and needs.

Competition between energy sources already drives efficient investment decisions and disciplines networks against inefficient capital expenditure, particularly for gas which has always been a fuel of choice for most customers. It ensures that any capital expenditure undertaken is efficient, commercially justified and in consumers' long-term interests. Additional regulatory prescription would duplicate this existing discipline and risk constraining customer choice, driving inefficient outcomes that reduce, not enhance, consumer welfare.

### Gas distributors should consider the value that gas consumers place on reliability

We agree that reliability is an important aspect of service valued by customers. Reliability is fundamental to safety, public confidence and network value, and is not a feature customers expect to accept reductions on. Gas networks are already among the most reliable parts of Australia's energy system, far exceeding electricity networks in performance. According to the AER's *2024 Electricity and Gas Network Performance Report*, electricity networks experience on average 0.9 planned or unplanned outages per customer each year, whereas gas networks experience fewer than 0.01 outages per customer per year, or roughly one outage every 100 years on average.[xii]

Gas outages occur so infrequently that estimates of customers' willingness to pay for reliability have limited empirical meaning, as few customers have direct experience of gas service interruptions. By contrast, the higher frequency of electricity outages allows more robust valuation studies. Nonetheless, customers consistently indicate that reliability and safety are non-negotiable attributes of gas supply, and any reduction in these standards would be inconsistent with the NGO. We note that the regulators already monitor and report on network reliability in their annual performance reports, providing transparency and accountability under the existing framework.

### Gas distributors should account for future abolishment costs in cost benefit analysis

Requiring future abolishment or decommissioning costs to be included in cost-benefit analysis is conceptually inconsistent unless networks are also permitted to recover those costs through a corresponding revenue allowance. The proposed approach would introduce costs into the assessments that cannot be recovered under the regulatory framework, biasing the analysis against efficient investment and creating a one-sided test that undervalues the long-term benefits of continued service provision.

Gas networks supply a broad mix of homes, businesses and industries, and it is well recognised by governments that gaseous fuels will continue to play an important role in Australia's future energy mix. In this context treating highly speculative abolishment costs as present day liabilities would be premature and risk discouraging efficient investment in infrastructure that remains essential to the energy transition.

It is also unclear why this requirement would apply only to gas networks. All energy delivery networks, including electricity, face long-term uncertainty regarding demand and technology change. Holding gas networks to a different standard would create clear regulatory asymmetry and distort efficient investment across the energy system.

### Gas distributors should explore lower cost options to meet regulatory obligations

As noted above, gas distributors already consider lower cost alternatives to investment in every capital expenditure proposal, including where capital expenditure is required to meet a regulatory obligation. However, distributors cannot be expected to assess the overall value (cost and reliability) of alternative services provided by other market participants. Competition between energy sources already drives efficient investment decisions and disciplines networks against inefficient capital expenditure.

### The regulator should be required to closely scrutinise replacement capital expenditure

Regulators already apply a high degree of scrutiny to proposed replacement capital expenditure, with safety as the central consideration. We have seen both the AER and ERA rigorously test the need, timing and scope of replacement programs, approving them only where the expenditure is supported by technical regulators as being consistent with safety obligations. Further, during Multinet's 2018–22 Access Arrangement review, the AER reduced the proposed mains replacement program from 595km to 543km, rejecting 12km of medium-pressure cast iron and 40km of early-generation High Density Polyethylene mains on the basis that these works were not justified at that time.

Replacement capital expenditure is fundamentally about maintaining the safety and integrity of the network. These programs are assessed as the lowest cost means of maintaining safety, and deferring or denying justified replacement would expose both the public and network operators to unacceptable levels of risk. Network assets inevitably degrade over time due to age, condition and external factors, and replacement is often the most efficient way to ensure continued safe operation.

The proposed additional assessment mechanism would not enhance this process and, in some respects, would be unworkable. For example, the proposal requiring distributors seeking to replace assets before the end of their originally projected lives to show why the need for early replacement was not foreseen at the time of the original investment would be impossible to address in most circumstances and impossible for regulators to assess. Requiring distributors to demonstrate why the need for replacement was not foreseen at the time of the original investment would force the AER and ERA to attempt to reconstruct what information, assumptions and technology existed decades ago and judge whether the asset's early degradation "should have been known." This is not a realistic or meaningful exercise and only adds administrative complexity without improving outcomes for consumers or safety.

Finally, much of our replacement expenditure arises from obligations imposed by safety and technical regulators, rather than from economic regulation alone. The AER and ERA's role sits alongside these frameworks, and its assessments already take these statutory safety requirements into account when determining prudency and efficiency.

### The NGR should exclude capital expenditure on renewable gases from reference tariffs

This proposal would be inconsistent with the NGL which explicitly recognises 'covered gases', including renewable gases. Excluding expenditure on renewable gases would be contrary to the law and unworkable in practice. A legislated decision has been made to extend the regulatory framework to explicitly include renewable gases. In any event, attempting to exclude covered gases from gas distribution networks is a policy decision that can only be made within the NGL, not through a rule change.

Capital expenditure incorporated into refence tariffs is only for reference services. Network expenditure to deliver reference services for any covered gas is no different, and should be treated no differently by regulators, than expenditure for natural gas. It is possible under the NGL to provide reference services for covered gases (several networks already do this or plan to do so in the future, including in response to third party requests for access by renewable gas producers). Therefore, it is essential that a network be able to incur capital expenditure relating to covered gases as it relates to the provision of reference services.

We also note that there is no inconsistency between making investments to enable covered gases to be delivered by a gas distribution network and proposing additional depreciation. As explained in our response to Question 1, economic asset stranding is the risk that regulatory prices may no longer be binding (including because of more competitive alternatives). The risk that expenditure on covered gases (relating to reference services) may not be returned persists for covered gases as it does for natural gas, with the same internal and external regulatory discipline restraining capital expenditure.

### The regulator should publicly consult on advance determinations on capital expenditure proposals

The advance determination process is intended for situations where capital expenditure must proceed within a regulatory period and cannot reasonably be deferred until the next access arrangement review. It provides a pragmatic mechanism for timely approval of essential, time-sensitive investment. Introducing a mandatory public consultation requirement would undermine this purpose by adding delay and administrative burden without clear benefit.

The regulators already have discretion to consult on advance determinations where they consider this appropriate, ensuring transparency while maintaining flexibility. Network capital expenditure is already subject to multiple layers of oversight and incentive regulation. Networks forecast capital expenditure at least five years in advance as part of each access arrangement, with allowances set through extensive public consultation. Following approval, networks are expected to continually refine their strategies and delivery programs to reflect actual conditions. The regulators subsequently assess all expenditure incurred during the period through its conforming capex review, ensuring all costs are efficient. In addition, the Capital Expenditure Sharing Scheme (CESS) actively encourages networks to minimise capital expenditure where performance can be maintained. Finally, under the NGR, regulators are able to review capex undertaken over the preceding AA period for prudency and efficiency; something which is not a feature of the electricity regime and which gives further scope to ensure that capex is efficient.

Given these existing safeguards, mandating additional consultation on advance determinations would duplicate established processes and risk delaying urgent works, often related to safety, reliability or compliance, which would be contrary to the NGO.

### 2.2 What do you consider would be the benefits and costs of ECA's proposed approach (for consumers, service providers and the regulator)?

The ECA's proposed rule changes would impose unnecessary prescription, whereby the existing framework already provides regulators with broad discretion to assess the efficiency and prudency of investment.

Introducing additional capital expenditure rules would increase administrative burden for both networks and regulators, reduce flexibility in decision making and ultimately raise costs to consumers without improving outcomes. In practice, many network challenges can be addressed through either capital or operating expenditure solutions. Making capital investment approvals more onerous would distort this balance by incentivising higher operating expenditure, which is often a less efficient and more costly way to manage the same risk.

By constraining the regulator's discretion and distorting efficient investment choices, the proposal would likely worsen outcomes for consumers. We do not see any benefits in the proposed approach.

**2.3 Are there any alternative, preferable solutions to address the issues identified by ECA with the current capital expenditure criteria?**

For the most part, the existing capital expenditure criteria are effective and provide regulators with the discretion necessary to address the issues raised in the rule change proposals. No changes are required.

**2.4 Do you consider changes are required to the rules in relation to advance determinations on capital expenditure in the context of the energy transition (rule 82)? If so, what are your views on the changes proposed by ECA (removing the provision or requiring the regulator to undertake consultation on proposals for advance determinations)?**

No change to the current rules is required. As outlined in our response to Question 2.1, Rule 82 already provides a balanced and effective mechanism for the timely approval of essential, time-sensitive investment. The AER and ERA have discretion to consult where appropriate, ensuring transparency without unnecessary delay or administrative burden.

Removing the provision or mandating consultation would duplicate existing safeguards, add cost and complexity, and risk delaying critical safety, reliability or compliance works. The current framework already includes extensive oversight through access arrangement reviews, conforming capex assessments and the CESS. Further prescription is unnecessary and would not improve outcomes for consumers.

**2.5 Do you consider that additional types of expenditure may need to be recognised as capital expenditure in the context of the energy transition (e.g. decommissioning expenditure)?**

We do not consider any rule change is required at the present time for gas distributors to account for future abolishment or decommissioning costs in cost-benefit analysis. The existing framework already provides flexibility for networks and regulators to address these issues if and when they arise.

Under the NGR, expenditure must meet the prudency and efficiency tests set out in Rules 79 and 91. These provisions allow regulators to approve expenditure, including that associated with decommissioning, where it is efficient and in the long-term interests of consumers. This already gives networks the ability to recover efficient costs related to abolishment or decommissioning where such costs are necessary. Any future need for assistance, is best addressed through broader frameworks governing the potential wind-down of networks, rather than through amendments to the NGR itself, given the importance of these policies to decisions about the future of network infrastructure.

In practice, the framework has proven capable of managing these matters. Similar costs can be treated as operating or capital expenditure where justified, showing that the existing framework provides the flexibility to manage potential decommissioning costs without change. The recent connections rule change process also directly addresses the treatment of connection and abolishment costs, which together represent a significant portion of any potential decommissioning costs.

Requiring networks to forecast and include highly speculative abolishment costs in cost-benefit analysis would introduce unnecessary uncertainty and complexity. These costs are highly dependent on future government policies and long-term assumptions about the scale, timing and method of any decommissioning activity. Forecasting such costs decades in advance would not produce reliable or meaningful estimates and could bias investment decisions by embedding assumptions about large-scale network closure that may never occur.

If governments were to introduce specific decommissioning policies or direct the retirement of parts of a network, those costs should be managed through explicit government programs rather than pre-emptive regulatory adjustments. The existing framework already allows regulators to consider and approve prudent and efficient expenditure for decommissioning where justified. We therefore consider that no further rule change is warranted.

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| **Q3 – Operating expenditure** | **3. Are any changes required for operating expenditure?**<br><br>Changes to the operating expenditure rules are not necessary. As with capital expenditure, the AER and ERA already have broad discretion to assess the efficiency and reasonableness of operating expenditure.<br><br>**3.1 Do you consider the current definition of operating expenditure (which includes expenditure for increasing long-term demand for pipeline services) is fit for purpose in the context of the energy transition?**<br><br>The current definition of operating expenditure, which includes expenditure to increase or maintain demand for pipeline services, should be retained. It provides flexibility to accommodate for differing circumstances across jurisdictions, including variations in government policy and outlooks on the role of gas within the transition to a net zero economy. Importantly, it also allows for investment in the growth of covered gases such as hydrogen and biomethane. Under Rule 91(1), such expenditure must still satisfy the test of being that which '*would be incurred by a prudent service provider acting efficiently*' [xiii]<br><br>Where government policy explicitly prohibits new gas connections or otherwise restricts or discourages network extension and expansion, it would not be prudent or efficient to incur expenditure aimed at increasing demand. Conversely, in jurisdictions where governments have not restricted gas usage, including for residential use, such expenditure may remain efficient where it supports demand for lower-emissions gases or reduces costs for other customers.<br><br>If the proposed rule changes seek to remove the ability for operating expenditure to support network growth on the assumption that gas networks will contract, logic would suggest an equivalent provision be introduced to allow operating expenditure for network contraction. No such proposal has been made.<br><br>Excluding the possibility of network growth would amount to a policy decision, not a matter for amendment through the NGR. The current definition appropriately limits growth-related expenditure to circumstances where it is efficient, and no amendment is required.<br><br>**3.2 Do you consider there are additional types of operating expenditure that may need to be recognised in the context of the energy transition?**<br><br>The current rules already enable the regulator to consider decommissioning related operating expenditure. Decommissioning of assets is a normal feature of network operations, for example where third-party works necessitate reconfiguration or removal of network infrastructure.<br><br>In practice, large-scale decommissioning would primarily involve capital expenditure, as it relates to the physical removal or retirement of network assets. Any associated operating expenditure would be minor and already captured under existing provisions. Because decommissioning typically occurs once the last customers have left the network, there would be no remaining revenue to fund these activities. Any provision for future decommissioning would therefore need to be made in advance while customers remain connected. This could be considered by regulators in future if large-scale decommissioning becomes likely, but it does not justify or require changes to the current rules.<br><br>The position outlined in the proposed rule changes presents a logical inconsistency. If networks were expected to cease investment and only maintain existing assets, operating expenditure would inevitably rise, increasing costs for consumers. The current framework already provides the flexibility to assess these trade-offs between capital and operating expenditure where appropriate. Additional prescription is unnecessary and would risk weakening regulatory certainty rather than improving it.<br><br>**3.4 Do you consider the regulatory framework appropriately balances the incentives between capital-intensive solutions and asset management or maintenance solutions so that service providers have incentives to consider the most efficient options to address network needs? If not, what changes would be required to balance these incentives?**<br><br>The existing framework already provides strong incentives for networks to balance capital and operating expenditure to achieve least-cost outcomes. The ability to substitute capital for operating expenditure is an important element of flexibility within the current rules, particularly in managing economic asset stranding risk, as operating expenditure does not create long-term liabilities. Considering alternative operating expenditure is a key issue networks consider in developing capital expenditure business cases but often entails higher upfront costs. Regulators must carefully assess the efficiency of these trade-offs and their implications for consumers. In the current rules and as demonstrated through numerous decisions the regulator has broad discretion to consider whether this substitution is efficient. No change to the rules is required. |

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| | In contrast, the current rule change proposals would significantly constrain the regulator's ability to choose the most efficient solution. The proposed changes to the depreciation and redundant assets rules, would mean that capital expenditure which is determined to be efficient at the beginning of one AA period, could be removed from the RAB in the future (even as soon as the next Access Arrangement). This would undermine confidence in the regulator's decisions and distort incentives, encouraging networks to adopt operating expenditure solutions even when capital investment would be more efficient.<br><br>Such a framework could lead to perverse outcomes. A network may propose an operating expenditure solution to avoid the risk that the regulator might decide to write down that asset in future, the regulator may require a capital solution because it is demonstrably more efficient, and yet part of that investment could still be written down later. This highlights why the proposed rule changes represent a fundamental departure from the NGO and the RPP: They would undermine incentives for efficient investment and weaken the trust and certainty on which regulatory decision-making relies. |

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| **Q4 – Risk and cost allocation** | **4. Does the current framework effectively manage and allocate risk and costs between consumers and network service providers in the context of uncertain demand?**<br><br>*Questions 4, 5 and 6 address closely interrelated issues surrounding uncertain demand, economic asset stranding and risk allocation, and proposed solutions to these issues. We discuss these issues more holistically in Attachment A which should be considered part of our response to these questions.*<br><br>As outlined in Attachment 1 and discussed in response to question 1, the risk of economic asset stranding – not physical stranding – is the risk the NGL and NGR seek to manage through the depreciation provisions, particularly Rule 89.<br><br>The NGO and NGR were deliberately structured to address the possibility of economic asset stranding by allowing for variation in depreciation. The current framework appropriately manages and allocates the risks and costs of economic asset stranding between consumers and network service providers in the context of demand uncertainty. The formulation of the NGR explicitly provides regulators with the ability to amend depreciation schedules to address future risks of economic asset stranding. Its wording is deliberately flexible: it does not prescribe specific preconditions, evidentiary standards, or thresholds that must be met before such adjustments can be made. The guiding principle is the promotion of efficient prices.<br><br>The proposed rule changes characterise the issue as one of "risk transfer" between consumers and networks. In reality, the existing NGR already defines and allocates this risk in a deliberate and balanced way through the depreciation provisions and the Revenue and Pricing Principles. The framework was intentionally designed to manage change and uncertainty, ensuring flexibility without undermining investor or consumer confidence.<br><br>This approach aligns closely with the *Window of Opportunity Passed* (WOOPS) framework developed by Crew and Kleindorfer,[xiv] which provides the theoretical basis for early regulatory action – often in the face of uncertainty – rather than delay. This flexibility enables regulators to act in a timely manner to safeguard efficient investment and long-term consumer outcomes. Further information is provided in Attachment 1, Section 2.1.<br><br>The depreciation rules operate within a broader context of economic regulation that is essential when considering whether the framework is effective in addressing the risks considered in this consultation. The Revenue and Pricing Principles (RPP) set out in section 24 of the NGL guide both regulators and the AEMC in achieving the NGO when setting regulated prices.<br><br>The principle in subsection (2) – that service providers be given a 'reasonable opportunity' to recover at least their efficient costs – is a cornerstone of economic regulation. Confidence in recovery is critical to maintaining investment in regulated assets, particularly under the uncertainty of the energy transition. Equally, maintaining this confidence benefits consumers by ensuring ongoing investment in safe and reliable infrastructure while avoiding higher costs that would result from premature asset write-downs, under-investment or higher required returns.<br><br>Other RPPs are also relevant in this context:<br><br>• Subsection (3) emphasises the importance of incentives for the efficient investment, operation and efficient use (as discussed above), as well as the incentive to operate the pipeline efficiently and the incentive to encourage efficient use of the pipeline (RPP2);<br>• Subsection (4) highlights the importance of maintaining continuity in asset values over time; and<br>• Subsection (5) that regulated prices should allow for a return that reflects the regulatory and commercial risks associated with providing the relevant service.<br><br>We note that similar principles operate in electricity, under Section 7A of the National Electricity Law.<br><br>The depreciation principles under NGR 89 must be read in conjunction with the RPPs and their protections and incentives. The Rules are intended to allow adjustment of economic lives as market conditions evolve to ensure that networks continue to have a reasonable opportunity to recover their efficiently incurred capital expenditure whilst those assets remain in use. This approach has been applied in practice, including in recent Access Arrangement decisions such as for the Victorian gas network businesses in the 2023 Victorian network reviews, where changes to depreciation schedules were accepted to manage emerging stranding risk. |

Attachment 1 Section 2.3 provides further detail on the original policy intent behind the depreciation provisions and why variation of economic lives was fundamental to the framework. Evidence from state regulators at the time responsibilities were transferred to the national regime confirms that the capacity to vary economic lives, including in response to asset stranding risks, was explicitly recognised as an essential component of the regulatory compact underpinning investment.

This historical context demonstrates that the proposed rule changes would fundamentally alter the nature and intent of the existing rules and broader regulatory framework, seeking to "fix" a problem that does not exist and in doing so, rewriting the balance of risk that was deliberately established in the NGL and NGR. The current framework remains the most effective and proportionate means of managing uncertainty while promoting the long-term interests of consumers.

**4.1 Do you agree with ECA and JEC that the current rules do not provide for appropriate consideration and management of assets at risk of becoming increasingly underutilised in the context of the energy transition, including consideration of how risk and costs are allocated between network service providers and consumers (including present and future consumers)?**

The proposals advanced by ECA and JEC address utilisation trends rather than the underlying risk of economic asset stranding, which is the relevant consideration under the NGL and NGR.

As discussed above in response to Question 4 and detailed in Attachment 1, the current framework can manage the relevant risks associated with assets at risk of economic stranding. Evolving regulatory practice demonstrates that the existing rules are effective and sufficiently flexible to address these risks. The AER's 2021 Information Paper provides a particularly authoritative reflection on economic asset stranding and the mechanisms for its management. Attachment 1 Section 2 further expands on AGIG's approach to this issue, with specific reference to our recent Access Arrangement proposal for AGN South Australia.

Economic asset stranding has a simple and rather narrow meaning. Under current arrangements, the prices which "bind" – that is, the prices which networks charge – are those determined by the regulatory building block model. However, as the energy market evolves, situations may emerge where consumer willingness to pay falls below the regulatory building block price. This may occur due to shifts in relative prices such as a reduction in the price of substitutes for gas or an increase in the cost of gas transport.

Where this happens, the network would not cease operations (except in extreme cases where prices could not cover even operating costs) but instead would set charges based on willingness to pay, rather than building block costs. Revenues will then not be sufficient to recover the efficiently incurred costs embedded in the RAB. The difference between revenue determined by willingness to pay and revenue required to recover efficient costs, expressed as a net present value, represents the quantum of economic asset stranding – that portion of the RAB which will not be recovered when prices fall below efficient costs. Unlike physical stranding, which affects specific assets such as pipes or valves, economic stranding is a system-wide characteristic of the network. The JEC proposal overlooks this distinction, tying depreciation adjustments only to the forecast redundancy of individual assets.

It is also important to distinguish between declining demand and declining connections. Attachment 2 Section 3.1 demonstrates that while residential consumption per connection has moderated in recent years, growth in connected customers has continued to grow consistent with historic rates. Commercial and industrial consumption, which represents a major component of total network use, has remained steady. Connections, not throughput, are the key determinant of network utilisation and cost recovery. A decline in total demand therefore does not necessarily imply underutilisation or stranded assets.

A central feature of the regulatory framework, and Rule 89 in particular, is the ability to respond to potential economic asset stranding in a timely manner, before reaching the point described in economic literature as the WOOPS point – the 'window of opportunity past'.[xv] The WOOPS point represents the stage at which adjustments to depreciation would produce regulatory building block prices exceeding levels sustainable in the market. Beyond this point, solutions would need to be sought outside the regulatory framework, because it represents the extreme case where regulatory prices no longer bind.

Regulators have explicitly considered the WOOPS point in several Access Arrangement decisions for gas distribution networks, including all AGIG distribution networks and transmission pipelines such as AGIG's Dampier Bunbury Natural Gas Pipeline. The relevant risk being considered by regulators is the risk of

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| | economic asset stranding, not the underutilisation of individual assets. This distinction is important because underutilisation alone does not create a regulatory problem unless it affects the ability to recover efficient costs.<br><br>AGIG's networks and pipelines have not reached the WOOPS point. Additional depreciation as proposed can still be applied without undermining the competitiveness of regulatory prices relative to alternatives. While some networks may approach the WOOPS point sooner than others, the majority of Australian gas distribution networks retain sufficient flexibility under the current framework to manage these risks effectively without rule change.<br><br>**4.2 Are there alternative solutions to those proposed in the ECA and JEC's rule change requests that would more effectively address cost recovery risks for efficient past and future investments?**<br><br>The existing rules adequately address the risk of economic asset stranding. This is evidenced in practice by the AER's acceptance of Victorian gas network businesses' 2023 proposal to vary depreciation schedules to reflect emerging stranding risk, demonstrating that the framework already provides the flexibility required to manage these issues effectively.<br><br>Through Rule 89, regulators already have the discretion to vary depreciation schedules and other parameters to respond to emerging stranding risk in a timely and proportionate manner. The framework, together with the evolving approaches adopted by AGIG, regulators and other networks, does not eliminate the risk, which would be impossible, but allows it to be managed while maintaining the principles of the NGO and RPP.<br><br>This balance ensures that investors and consumers share risk appropriately, supporting continued investment while protecting consumers from inefficient costs. As explained in response to questions 5 and 6 below, the proposed rule changes would fundamentally alter the framework, undermining the existing principles of the NGL and reducing regulatory certainty. Such outcomes would be inconsistent with the achievement of the NGO. |
| **Q5 – Depreciation (ECA)** | **5. How does ECA's proposal impact the recovery of capital costs for new and existing assets?**<br><br>*Questions 4, 5 and 6 address closely interrelated issues surrounding uncertain demand, economic asset stranding and risk allocation, and proposed solutions to these issues. We discuss these issues more holistically in Attachment A which should be considered part of our response to these questions.*<br><br>As discussed in response to questions 1 and 4, the ECA's proposed rule changes — and those of JEC[xvi] – would fundamentally alter the recovery of capital costs for both new and existing assets. The current framework provides regulators with flexibility to adjust depreciation to manage risk while maintaining confidence in cost recovery. The proposed amendments would remove this balance and introduce uncertainty for both investors and consumers.<br><br>Amending the depreciation rules as proposed would have two major consequences:<br><br>• Materially weakening investment incentives across the energy infrastructure sector, undermining confidence in long-term cost recovery and increasing financing costs for all users; and<br>• Placing regulators in a conflicted position, as implementing the proposed changes would be inconsistent with the NGL and the RPP.<br><br>As a result, the proposed rule changes do not meet the threshold test of contributing to the achievement of the NGO. Attachment 1 Section 3 provides detailed analysis of these consequences which are introduced in response to the questions below.<br><br>**5.1 Do you consider changes are required to the depreciation provisions in the context of the uncertain outlook for gas demand (in terms of limiting variations to the rate of cost recovery and changes to asset lives)?**<br><br>The existing framework provides sufficient flexibility to accommodate uncertain gas demand and no changes to the depreciation provisions are required. The current provisions already enable regulators to vary depreciation schedules to address the risk of economic asset stranding where appropriate.<br><br>The depreciation provisions are fit for purpose and consistent with the objectives of the NGL and NGR. As outlined in our response to Question 4 (and its sub-questions) and in Attachment 1, Section 2.3, the current provisions were deliberately designed to manage change and ensure a balanced allocation of risk between consumers and service providers. They remain effective and do not require amendment. |

**5.2 What do you consider would be the benefits and costs of ECA's proposed approach to restrict the use of accelerated depreciation through variations to the rate of cost recovery and changes to asset lives (for consumers, service providers and the regulator)?**

### Investment and the proposed rules

Regulators currently approve investments on the basis that networks are likely to recover efficiently incurred capital. While unforeseen events may occur that prevent this outcome, the principle of a 'reasonable opportunity' to recover efficient costs, together with the other RPP discussed in response to Question 4, affords investors a high degree of confidence. This confidence is supported by the existing depreciation rules, which allow the regulator to vary depreciation to respond to emerging risks.

Under the proposed rule changes, the presumption that regulated networks will be afforded a reasonable opportunity to recover efficiently incurred investment would no longer hold. A regulator could initially intend for a network to recover the capital invested in a long-lived asset, such as a 50-year pipeline, but then revise that intent in the next Access Arrangement based on a new forecast of demand or utilisation. By altering such forecasts, the regulator would, in effect, crystallise potential future losses by writing down the RAB in the present, in anticipation of events that may or may not occur. This would represent a fundamental change to the current framework and a materially different investment proposition for regulated businesses.

The immediate impact would be a significant contraction in investment, as investors are unlikely to commit capital in an environment where it can be appropriated based only on forecasts. Customers who remain on the network and require investment to meet their needs would be disadvantaged. They may be unable to secure the gas they need or may need to negotiate outside the regulatory framework, which would have lost the trust that currently enables capital to be invested at relatively low cost. The outcome envisaged by the proposed rule changes would thereby become self-fulfilling, driven by regulatory intervention rather than by market dynamics or policy evolution. This would have significant consequences for customers and industries that choose not to electrify, or cannot feasibly or economically do so, including many homes, businesses and industrial users (refer Attachment 2, Section 1.2 for discussion of customer diversity on AGIG's gas distribution networks).

The consequences of adopting such an approach would not be confined to gas infrastructure. Adopting such a rule would signal to investors across all regulated sectors that ex-ante capital revaluation could be extended to their assets. This would raise financing costs across the energy sector and erode the stability that underpins efficient investment. This is why there are no examples of other jurisdictions adopting the approach in the proposed rule changes (as outlined in Appendix A of the AEMC's consultation paper), and why the broader body of economic regulation literature consistently cautions against the approach in the proposed rule changes.

### Implementation by regulators

As outlined in more detail in Attachment 1 Section 3.3, the proposed changes are fundamentally inconsistent with the NGO and RPP that regulators could not lawfully apply the proposed rules while still meeting its obligations under them.

The NGO requires efficient investment in, and operation and use of, services for the long-term interests of consumers. The newer emissions control requirements require consideration of the achievement of targets set by participating jurisdictions. However, under the building-block framework, writing down an asset would distort prices. Prices would be set artificially low, encouraging inefficiently high use of the network, and conflicting with the emissions-reduction objectives of the NGO.

Similar issues arise in relation to the RPP:

- Writing down the value of RAB while assets remain in service and continue to provide economic value cannot be considered as providing a 'reasonable opportunity" to recover efficient costs;[xvii]
- Networks cannot promote efficiency in the use of services if past regulatory actions result in inefficient prices that cannot be reversed.[xviii] A tariff that crystalises potential future asset stranding into an immediate loss introduces a new regulatory risk that is not currently priced, and would therefore need to be priced;[xix]

- A regulator cannot reasonably consider the costs and risks of under-investment when its own actions, in following the proposed rule changes, would directly discourage investment; [xx]
- The economic costs and risks of over- or under-utilisation could not be managed if networks and regulators are unable to respond to over-use because past actions have set prices at inefficiently low levels. [xxi]

Taken together, these issues demonstrate that the proposed rule changes fail the rule-making test. They cannot be applied in a way that contributes to the NGO or remains consistent with the RPP.

**5.3 What are your views on ECA's alternative solution of prohibiting the regulator from varying the depreciation rates for existing assets?**

The alternative solution would bring all the same costs outlined above, albeit to an even greater degree with economic asset stranding risk transferred entirely to networks.

This would represent a fundamental change to the regulatory compact. When the current framework was established, long asset lives were paired with the flexibility to vary them as market conditions evolved (see Attachment 1). This balance allowed consumers to benefit from lower prices at the outset, with the understanding that depreciation could later change if circumstances required. The alternative proposal would remove that flexibility and, in effect, change the deal by shifting all risk onto networks after consumers have already received the benefits.

It is the clear intent of the Rules for economic lives to change as market conditions evolved, ensuring that networks continue to have a reasonable opportunity to recover their efficiently incurred capital expenditure while those assets remain in use. Asset lives have been established, modified and applied under this framework with full knowledge of that intent.

Making rule changes for the alternative solution would create even greater uncertainty for investment, undermining investment across regulated utilities and put regulators in a conflicted position of implementing the rule changes while remaining consistent with the NGO and RPP.

**6. How does JEC's proposal impact the recovery of capital costs?**

*Questions 4, 5 and 6 address closely interrelated issues surrounding uncertain demand, economic asset stranding and risk allocation, and proposed solutions to* these *issues. We discuss these issues more holistically in Attachment 1 which should be considered part of our response to these questions.*

JEC's proposal, while operating through different rule provisions, would have effects equivalent to those arising from the ECA proposal discussed in our response to Question 5.2. The existing redundant assets provisions in Rule 85 allow the regulator to declare an asset redundant only after it has in fact ceased to contribute to the delivery of pipeline services. When this occurs, the asset is removed from the RAB and the regulator has flexibility to determine how any unrecovered costs are treated.

This approach appropriately manages risk by reflecting actual outcomes rather than forecasts. It recognises that networks, like any business, face the possibility that market conditions may change, and provides a mechanism for regulators to respond to that reality when and if it arises.

Under JEC's proposal, this process would shift from an ex-post to an ex-ante determination, enabling regulators to write down assets based on expectations of future utilisation. Such an approach would fundamentally alter the intent of Rule 85, transferring all stranding risk to networks and creating uncertainty for investors, regulators and consumers alike. The current provisions are an important tool for regulators in rare cases where assets truly cease to contribute but would become unworkable if applied in advance of events.

**6.1 Do you consider new planning-related reporting obligations for network service providers are required in the NGR to support more efficient decision-making by stakeholders? If so:**

**(a) what information should be reported and for what purpose?**
**(b) what should be the reporting frequency?**
**(c) what pipelines should the requirements apply to: scheme, non-scheme, distribution, transmission?**

The NGL does not confer planning powers on any market body in respect of gas distribution networks or pipelines. While additional information may assist regulators such as the AER and ERA in exercising their existing functions – particularly in Access Arrangement determinations – any new reporting obligations must be clearly linked to those statutory purposes.

Requiring networks to provide information beyond what is necessary to support these existing functions would be inefficient, impose unnecessary costs, and risk creating distortions in regulatory decision-making.

**6.2 Do you consider the definition of redundant assets should be amended as proposed by JEC to include:**

**(a) assets that are economically inefficient to use?**
**(b) anticipated redundant assets?**

Gas distribution networks operate as integrated systems rather than individual assets. As a result, the risk of economic asset stranding affects the whole RAB, not individual components. Economic stranding is a system-wide issue that is distinct from physical redundancy. The attempt in the proposed rule change to link depreciation tightly to specific physical assets is therefore misplaced.

The proposal to identify assets that are "economically inefficient to use" revisits an earlier rule change proposal considered by the AEMC in 2012 (available here) whereby the Major Energy Users Group proposed that assets which are currently underutilised (not forecast to be underutilised, as per the JEC proposal) could be "re-optimised" out of the RAB. The AEMC ultimately concluded that this proposed rule change would not be in the long run interests of consumers, due (among other issues) to concerns about the impacts on investment. We provide further detail in respect of this previous rule change, and the parallels it has with the current proposed rule changes, in Attachment 1.

Regarding the proposal to determine some assets as 'anticipated redundant assets', we consider the approach and principles outlined in the AEMC consultation paper (p.26) to be unworkable. RAB values are large and many asset lives extend over several decades. Any depreciation changes designed to address stranding risk must therefore be made well before the risk materialises. If intervention is delayed until the risk has materialised, the adjustment becomes ineffective, as once the WOOPS point has been reached no recovery is possible. This point is well understood and recognised in the AER's 2021 Information Paper.

By contrast, declaring assets as 'anticipated redundant assets' would require networks and regulators to predict, decades in advance, which specific assets will become redundant and to justify those assumptions in detail. This is unrealistic given the pace of change in the energy sector. The relevant task is managing the risk of economic asset stranding for the network as a whole, not to pre-emptively identify individual assets to be declared 'anticipated redundant assets'. The proposed approach would lock in losses for investors long before the future is crystalised, whereas the current depreciation framework enables investors and regulators to adjust to circumstances as they change.

Additionally, the proposed rule change allows no mechanism to correct mistakes. That is, if the forecast which is used to write down some portion of "anticipated redundant assets" in the RAB turns out to be wrong in future, there is no mechanism envisaged in the proposed rule change which would allow the write down to be reversed, or for customers to otherwise refund investors for a mistaken forecast by the regulator. This makes the proposed rule asymmetric in its application.

The result would be unworkable for regulators tasked with determining the value, or part thereof, of assets that are inefficient or anticipated to be redundant. Network depreciation schedules are structured by asset class, covering tens of thousands of individual assets. Disaggregating these classes to assess individual assets would be administratively impossible and would impose significant additional costs. Most importantly, the current rules allow the risks to be managed for the RAB, making them far more efficient and effective than the changes proposed.

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| | **6.3 Do you agree with JEC's proposal that service providers and the regulator should use accelerated depreciation in conjunction with the redundant asset provisions only if used to address capital cost recovery risks or redundancy?**<br><br>The rules for redundant assets and depreciation are not and should not be considered two sides of the same coin.<br><br>The flexibility to vary depreciation was deliberately introduced to enable the risk of economic asset stranding to be managed across the entire RAB, reflecting that it is the network as a whole that determines relative prices for consumers.<br><br>In contrast, the redundant asset provisions are designed to remove specific assets that have ceased to be used and to allow their remaining costs to be managed separately.<br><br>The proposed rule changes would incorrectly conflate physical stranding with economic asset stranding (as discussed in Attachment 1 Section 2).<br><br>**6.4 What do you consider would be the benefits and costs (for consumers, service providers and the regulator) of JEC's proposed approach to defining and assessing asset redundancy, and allowing for accelerated depreciation to address capital cost recovery risks only in conjunction with the redundant asset provisions?**<br><br>Please refer to our response to Question 5.2<br><br>**6.5 What are your views on JEC's alternative solution to outright prohibit the use of accelerated depreciation?**<br><br>Please refer to our response to Question 5.3 |
| **Q7 – Planning requirements (ECA)** | **7. Are new planning requirements necessary?**<br><br>Networks are already subject to significant reporting obligations, under the NGL and NGR, as well as through other regulatory processes, including those overseen by safety regulators. Scheme pipelines that are distribution networks regulated by the AER and ERA are required to prepare annual Regulatory Information Notices (RINs), which require substantial detail on operating costs, capital expenditure, demand and other key information. These pipelines must also meet ongoing and annual disclosures under Part 10 of the NGR, which include annual financial reports covering profitability and debt instruments, as well as data on service usage information, historical demand, and actual prices payable.<br><br>In addition, the five-yearly Access Arrangement processes include extensive reporting directly relevant to the matters under consultation. Access Arrangements contain detailed demand forecasts, some of which are confidential, that directly inform regulators' decisions. Furthermore, as additional depreciation has become more significant for AGIG assets, these forecasts also include detailed information outlining long-term demand scenarios and, where possible, simulations that account for technological, policy and market developments. While much of this information supports regulatory decision-making, it is not expressly mandated by the NGL or NGR. Rule 42(1)(b) ensures that Access Arrangements must already provide supporting information sufficient 'to understand the basis and derivation of the various elements of the access arrangement or the access arrangement proposal'.[xxii] Rule 43 gives the regulator power to require additional information. Prescribing new, specific information requirements risks duplication, cost and confusion with existing processes.<br><br>As outlined in Attachment 2 Section 2.3.4, no Australian jurisdiction is currently contemplating the full decommissioning of gas networks. Even in the ACT, the only jurisdiction to announce a long-term phase-out, no practical framework yet exists for retiring or repurposing network assets. Other governments have taken clearer positions in support of continued access. For example, the Victorian Government explicitly ruled out a statewide gas appliance ban following its 2025 Building Electrification RIS. These positions confirm that across jurisdictions, policy direction continues to support ongoing use of gas networks.. On this basis, additional planning-style reporting is not warranted by current policy settings.<br><br>Given the breadth of information, additional reporting requirements are unlikely to deliver material benefits in supporting the energy transition. We agree with the AEMC's initial view (AEMC consultation paper p.29) that: |

*'There is a need to consider both the extent and the quality of the planning information that gas distributors would be required to publish under this rule change. Releasing more information by itself may have limited value if it does not enable stakeholders and policy makers to fully understand, assess and input into gas distributors' decisions. Therefore, any planning document would need to be based on a transparent planning methodology set out in the rules to ensure effectiveness plus consistency across the networks. How this interacts with the access arrangement process is another consideration.'*

The NGL does not confer planning powers on a market body for gas distribution networks or pipelines. Any new reporting should therefore be clearly linked to existing statutory functions and demonstrate a net benefit relative to the costs of production, publication and confidentiality management. No additional requirements should be imposed without a thorough review of existing obligations and a clear case that they are necessary, proportionate and complementary to the Access Arrangement and Regulatory Information Notice (RIN) processes.

**7.1 Do you consider new planning-related reporting obligations for network service providers are required in the NGR to support more efficient decision-making by stakeholders? If so:**

**(a) what information should be reported and for what purpose?**
**(b) what should be the reporting frequency?**
**(c) what pipelines should the requirements apply to: scheme, non-scheme, distribution, transmission?**

The NGL does not confer planning powers on any market body in respect of gas distribution networks or pipelines. While additional information may assist regulators such as the AER and ERA in exercising their existing functions – particularly when assessing Access Arrangement proposals – any new reporting obligations must be clearly linked to those statutory purposes.

Requiring networks to provide information beyond what is necessary to support these existing functions would be inefficient, impose unnecessary costs, and risk creating distortions in regulatory decision-making.

**7.2 What do you consider would be the benefits and costs of ECA's proposed reporting requirements (for consumers, industry, gas and electricity network businesses and the regulator)?**

Network operators already incur significant costs in meeting current reporting obligations, often far exceeding official estimates. Significant work is required to ensure that our data meet regulator-specific requirements, which differ from standard corporate reporting under the *Corporations Act.* For example, the preparation of Regulatory Information Notice data requires 10,000 labour hours each year.

Certain elements of the proposed rule would impose particularly high costs without clear benefit. For instance, the proposal to require expected useful lives for every individual asset would be redundant. Under the Post-Tax Revenue Model (PTRM) used by regulators, assets are already grouped by class, and useful lives can be derived directly from those classes. Disaggregating these into thousands of individual assets would be an onerous and costly exercise, whereby the proposed rule changes have not demonstrated any marginal benefit beyond what is already achieved through existing reporting.

Current RIN, Access Arrangement and Part 10 disclosures already provide regulators and stakeholders with detailed information on network performance, costs and forecasts. The consultation paper does not identify any specific information gaps or evidence that existing data is insufficient to support efficient decision-making. In the absence of such evidence, the proposed new reporting requirements would increase administrative burden without delivering measurable improvements in transparency or regulatory outcomes.

**The proposed requirement for a 20-year planning horizon with scenario-based analysis:**

Our five-yearly depreciation proposals already extend beyond 20 years as we believe this level of information is necessary to support the nature of our proposals. Over time, AGIG has transitioned from using scenarios to, where possible, providing simulations that better capture uncertainty in outcomes. In considering what information is necessary to support informed, long-term decision-making, we believe the existing provisions under the NGR (specifically Rule 42(1)(b) and Rule 43 are sufficient.

Rule 42(1)(b) already requires Access Arrangements to include sufficient information to understand the basis of each element of the proposal. Where a proposal includes variation to depreciation, this rule necessitates the sort of long-term information imagined by the proposed rule. Additionally, Rule 43 empowers regulators to request additional information where the information provided is deficient. Adding further specificity, as proposed, would unnecessarily constrain how long-term analysis is undertaken. The current rules give networks and regulators the flexibility to determine what information is most relevant to the decision at hand, which will naturally vary across networks.

**Potential augmentation projects and the drivers for these:**

This information is already provided in significant detail with each Access Arrangement. Between Access Arrangements, absent of major shocks, we focus on delivering what we have promised and what has been approved in the Access Arrangement and what our customers expect. No additional reporting requirements are necessary.

**Alternative investment projects:**

Capital expenditure business cases already included consideration of potential alternatives. We are unaware of additional 'alternatives' that could be meaningfully reported.

**A consumer engagement strategy:**

Consumer engagement is an ongoing part of our business including regular surveys and engagement as part of Access Arrangements. This has become a standard part of practice for regulated networks and is designed to help regulators make decisions. No change to the current rules is required.

### 7.3 Do you consider that any alternative solution would better promote the long-term interest of consumers?

AGIG remains open to collaborative approaches to ensuring stakeholders have all the information needed to understand the complex issues associated with Access Arrangement proposals and decisions. We acknowledge that depreciation and economic asset stranding are complex issues and are therefore open to considering ways in which the information, proposals and differences across networks can be better understood.

We note that the existing approach to profitability reporting to the AER and ERA was developed jointly by the regulators, consumer stakeholders and networks in 2019. The process to develop this reporting, whereby all parties could see what was desirable and what was feasible in respect of reporting a complex topic such as profitability, ensured the reporting has enduring utility and is practical to gather.[xxiii]

As noted above, the AER and ERA have powers to specify the information required and could collaborate with networks and stakeholders to ensure that the information provided with each Access Arrangement proposal on approaches to depreciation meets the requirements of the NGR. It is more appropriate for the AER and ERA to determine, through their existing powers and established consultation processes, what additional information may be required over time, rather than prescribing detailed requirements in the NGR. This approach maintains flexibility and ensures that reporting remains proportionate, targeted and responsive to emerging issues.

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| **Q8 – Longer-term outlooks** | **8. Would a longer-term outlook on the gas transition support better regulatory decision-making? What do you consider would be the costs and benefits of requiring service providers to provide demand and expenditure forecasts over a longer period than the relevant access arrangement period? What would be an appropriate longer-term period (e.g. 10, 15 or 25 years)?**<br><br>As introduced above, AGIG has provided long-term outlooks in Access Arrangement proposals for all networks and pipelines in recent years. Rule 42(1)(b) requires Access Arrangements to include sufficient information to explain the basis and derivation of each element of a proposal, including depreciation. Long-term outlooks are therefore already integral to regulatory decision-making, as depreciation decisions necessarily extend well beyond a single Access Arrangement period.[xxiv]<br><br>While additional information can be useful, more is not always better. Excessive prescription risks creating an illusion of precision or directing effort toward information that is not meaningful for regulatory purposes. Forecasting the energy transition is inherently uncertain, and the current rules strike the right balance by allowing networks and regulators to determine what information is relevant to each decision.<br><br>In AGIG's current approach to depreciation, consistent with the rules, we model how customers respond to changing prices to test the outcomes of different depreciation pathways. Our Customer Choice Model reflects the logic of the WOOPS framework, recognising that demand depends on how customers respond to changes in relative prices between gas and electricity. Forecasts made without this behavioural context risk being not only wrong but misleading.<br><br>Emissions targets and jurisdictional policies are also not forecasts in themselves. We take these policies into account only where they have direct implications for customer behaviour – such as a ban on new gas connections – while recognising that consumers retain choice across jurisdictions. Our approach to depreciation and long-term planning must therefore reflect this diversity of policy settings and customer decisions within the broader transition to net zero.<br><br>The Commission's suggestion (AEMC consultation paper p. 32) that networks should be required to develop optionality around decommissioning and redundancy appears unbalanced. A prudent and efficient operator, as AGIG does, already considers both decommissioning and reuse options, including how renewable gas investments can extend the life or function of existing assets. Balanced assessments of these options support more informed discussion of the future use of key assets and can reduce overall energy costs by avoiding premature asset stranding and unnecessary new investment.<br><br>The NGR already enables networks to make these balanced assessments, and we would discourage any rule changes that focus solely on decommissioning or other asymmetrical approaches. |
| **Q9 – Tariff variation mechanisms** | **9. Are changes to reference tariff variation mechanisms necessary?**<br><br>The current tariff-setting framework under Rule 93 of the NGR provides both networks and regulators with sufficient flexibility to determine an appropriate form of revenue control for each Access Arrangement period; whether it be a revenue cap, price cap, a hybrid of the two or some other mechanism entirely. Further rule-based guidance is not required.<br><br>**9.1 Do you consider the NGR should provide more guidance to the regulator on when different reference tariff variation mechanisms (e.g. revenue cap vs price cap) should be used by service providers to appropriately allocate intra-period demand risk between the service provider and users?**<br><br>Revenue and price caps are not, in themselves, mechanisms for addressing economic asset stranding risk. The relative efficiency of either model depends on the circumstances of the network or pipeline being assessed. Prescriptive guidance on when one model should be preferred over the other risks constraining regulatory discretion and entrenching arrangements that may be inefficient in particular contexts.<br><br>**9.2 If so, what would be the costs and benefits to consumers, service providers and regulators of providing more guidance in the NGR and/or bringing forward the regulator's decision on the applicable reference tariff variation mechanism?**<br><br>Regulators can already assess whether revenue or price caps should apply to a particular network and can require additional information from networks to support their decision-making. Further guidance in the rules is unlikely to deliver any additional benefit to consumers, service providers or regulators. |

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| **Q10 – Tariff rules** | **10. Are changes to the tariff rules necessary?**<br><br>The current tariff-setting framework provides sufficient flexibility for networks to develop efficient pricing structures. While cost-reflective tariffs are desirable, further rule-based guidance would risk inefficiency for two reasons. First, the information burden associated with implementing highly detailed cost-reflective pricing is substantial and subject to significant uncertainty. Second, retailers are not obliged to pass through network tariffs directly to customers, limiting the effectiveness of more granular price signals.<br><br>In practice, the current approach, which allows for change in pricing structures depending on the circumstances of individual pipelines, has proven both efficient and effective. Regulators, already exercise discretion in this area, reflected in recent decisions such as the Jemena Gas Networks Access Arrangement. No change to the existing rules is required. |
| **Q11 – Access arrangement periods** | **11. Should the regulator be able to require shorter or longer access arrangement periods?**<br><br>Existing arrangements, which allow networks to propose different Access Arrangement periods, are likely sufficient. However, AGIG is open to considering whether regulators should have more explicit powers to require an Access Arrangement period to be shortened or lengthened in exceptional circumstances.<br><br>As to whether longer or shorter periods are worth exploring, in most cases neither appears feasible or desirable:<br><br>• Shorter Access Arrangement periods must consider that the process required to complete an Access Arrangement proposal now typically exceeds two years from consultation on a reference service proposal through to a final regulatory decision. Given these statutory timeframes, shorter Access Arrangement periods would be impractical in most circumstances.<br>• Longer Access Arrangement periods raise different challenges. As noted in response to Question 8, long-term forecasts of capital and operating expenditure and demand become increasingly uncertain over time, creating greater risk and potential price volatility for customers.<br><br>On balance, we believe no change is warranted to the current rules.<br><br>**11.2 What do you consider would be the benefits and costs of aligning the timing of electricity and gas distribution decisions in relevant jurisdictions? What impacts would the alignment of these decisions have on regulators, service providers and stakeholders engaging in these processes?**<br><br>AGIG considers it unlikely that aligning the timing of AA decisions across electricity and gas networks within jurisdictions would deliver any material benefit. In principle, alignment could assist with coordination between sectors, for example in reconciling assumptions about future electrification and how many customers may switch energy sources. In practice, this information is already shared through existing consultation and forecasting processes.<br><br>Alignment would not meaningfully improve the accuracy of long-term demand forecasts. Customers typically switch from gas to electricity, or vice versa, at the end of appliance life, which occurs gradually and predictably across the network rather than according to regulatory timetables.<br><br>There are also significant practical issues that would impose costs on networks. Both gas and electricity networks would need to adjust core aspects of their regulatory proposals linked to broader financing arrangements. For example, averaging periods for debt might need to change, requiring the unwinding of hedges predicated on refinancing at a specific time of year. This would be expensive, complex and potentially destabilising. Changes to capital expenditure planning and other internal processes would also be required to align timetables.<br><br>On balance, any additional benefits of aligning decision timeframes are likely to be minimal, while the administrative and financial costs would be substantial. |

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| **Q12 – Re-opener provisions** | **12. Are changes required to the re-opener provisions?**<br>The existing re-opener provisions effectively manage unforeseen events and should not be expanded. The current balance between flexibility and stability is appropriate. |
| **Q13 – Incentive mechanisms** | **13. Should there be changes to the existing or additional incentive mechanisms? Do you consider modified or additional incentive mechanisms should apply to service providers in the context of the energy transition?**<br>The energy transition is guided by a clear long-term end point in the form of emissions targets, but the mechanisms and forms of energy available to get there and after achieving net zero are subject to a high degree of uncertainty.<br>Jurisdictional policies already incentivise customers and networks in different ways and should be allowed to take effect without requiring additional incentives in the NGR. Stipulating a particular incentive in the NGR runs the risk of pushing the industry towards a pre-determined, and possibly inefficient, outcome.<br>Furthermore, the risk of economic asset stranding acts as a significant incentive itself. As detailed in Attachment 1, as the energy market evolves, situations may emerge whereby consumer willingness to pay falls below the regulatory building block price due. This may occur due to shifts in relative prices such as a reduction in the price of substitutes for gas or an increase in the cost of gas transport, causing economic asset stranding.<br>The existing rules, which under rule 98 allow networks to propose incentive mechanisms and allow the regulators to require incentive mechanisms to be included within an Access Arrangement, should be maintained. |
| **Q14 – Pipeline elections** | **14. Could the proposed changes inefficiently incentivise pipeline elections? Would any of the changes considered in this consultation paper alter the incentive for non-scheme pipelines to elect to become scheme pipelines?**<br>The proposed rule changes regarding depreciation and redundant assets would deter any pipeline from electing to become a scheme pipeline.<br>The proposed rule changes undermine the value of the regulated asset base, making it subject to change before uncertainty about the future is resolved, and in doing so would introduce significant new uncertainty for investors. We consider no reasonable investor would elect for a non-scheme pipeline (or proposed pipeline) to become a scheme pipeline given the significant uncertainty that would be introduced as a result of the draft rules.<br>Furthermore, even if the proposed rules were applied only to pipelines that are gas distribution pipelines, the proposed changes would also likely deter any transmission pipeline, and any future covered gas pipeline, from electing to become a scheme pipeline—the making of the proposed rule change would in and of itself set a precedent that the NGR (and for that matter the National Electricity Rules) can be changed to undermine the value of investments that were previously determined to be efficient.<br>As outlined in response to several questions above, the making of the proposed changes for depreciation and redundant assets would be inconsistent with the NGO and the RPP. The proposed change would fundamentally change the nature of economic regulation. |
| **Q15 – Lessons from other jurisdictions** | **15. What can we learn from other jurisdictions/sectors?**<br>**Do you consider other changes to the regulatory framework for scheme pipelines are necessary to provide the regulator with the tools and appropriate level of discretion to manage the gas transition? If so, what would be beneficial?**<br>It is apparent from Appendix A2 of the consultation paper that the AEMC has already engaged in considerable learning from other jurisdictions. AGIG supports the AEMC's conclusion drawn from this analysis that *'regulators have:*<br>• *considered the regulatory framework holistically;*<br>• *sought to preserve the ability of regulated businesses to recover their efficient costs; and* |

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| | • *balanced price impacts for consumers with advancing capital cost recovery.'*[xxv]<br><br>We also highlight the conclusion that:<br><br>'*A key regulatory principle underpinning approaches by regulators around the world to address asset stranding risk is that a regulated service provider should have a reasonable opportunity to recover its prudent and efficient costs. That is, over the economic lifetime of an asset, the service provider should have a reasonable opportunity to:*<br><br>• *earn a return commensurate with the risk of the investment, and*<br>• *fully recover the capital invested in the asset (i.e. through depreciation).'*[xxvi]<br><br>Furthermore, the corollary to this important principle that:<br><br>'*In the majority of examples we considered, regulators have brought forward capital cost recovery to address asset stranding risk from declining demand. The most common way that regulators have brought forward cost recovery – including in Australia – is by accelerating depreciation.'*[xxvii]<br><br>These conclusions align with our understanding derived from international businesses that share common owners with AGIG.<br><br>The NGL and NGR in so far as they deal with the economic regulation of scheme pipelines, is very closely aligned with economic regulation in other jurisdictions as they reflect key principles of regulatory economics. When considered in contrast to the international case studies, it is clear that the proposed rule changes would in fact be at odds with these long-standing principles and the economic theory that underpins them. |
| **Q16 – Assessment framework** | **16.Do you agree with the proposed assessment criteria? Are there criteria that you consider are not directly relevant to the issues raised in the rule change requests and the proposed solutions?**<br><br>AGIG is generally supportive of the proposed assessment criteria at a headline level. However, we note that the 'Principles of market efficiency' and 'Principles of good regulatory practice' could more explicitly reflect the economic principles embedded in the NGO and RPP both of which are fundamental to the economic regulation of gas infrastructure.<br><br>We also note that the NGO, which defines the objective of the NGL, is with reference to '*the achievement of targets set by a participating jurisdiction (i) for reducing Australia's greenhouse gas emissions; or (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions*.[xxviii] The proposed assessment criterion 'emissions reduction: would the solution support emissions reduction?' is considerably broader in scope. To ensure consistency with the legislative framework, the criterion should explicitly recognise the importance of the emissions targets statement as required by section 72A of the NGL.[xxix] As outlined in Attachment 2, state and territory policies regarding natural gas vary significantly and it should not be assumed that the policies of one state will come to be adopted by all others. The AEMC's assessment of emissions reduction as a criteria in considering a rule change needs to be consistent with the variety of policies reflected (or in other cases those not included) in the emissions target statement. |

[i] Australian Energy Regulator (2021) *Regulating gas pipelines under uncertainty.* Available at: https://www.aer.gov.au/publications/reports/performance/regulating-gas-pipelines-under-uncertainty-information-paper.

[ii] Australian Energy Regulator (2021) *Regulating gas pipelines under uncertainty*, p.25. Available at: https://www.aer.gov.au/publications/reports/performance/regulating-gas-pipelines-under-uncertainty-information-paper.

[iii] Australian Energy Regulator (2021) *Regulating gas pipelines under uncertainty*, p.26. Available at: https://www.aer.gov.au/publications/reports/performance/regulating-gas-pipelines-under-uncertainty-information-paper.

[iv] Australian Energy Regulator (2021) *Regulating gas pipelines under uncertainty*, p.26. Available at: https://www.aer.gov.au/publications/reports/performance/regulating-gas-pipelines-under-uncertainty-information-paper.

[v] Australian Energy Market Commission (2025) *Gas Networks In Transition*, p.3. Available at: https://www.aemc.gov.au/rule-changes/gas-networks-transition.

[vi] Rule 79, *National Gas Rules* (2025).

[vii] Australian Energy Market Commission (2025) *Draft National Gas Amendment (Updating the regulatory framework for gas connections) Rule 2025.*

[ix] Replacing cast-iron pipes is one of the major costs associated with the transition to renewable gas. However, such works are also undertaken to enhance the safety and reliability of conventional natural gas networks. This reflects a common situation in which capital expenditure serves multiple regulatory and operational purposes, making it difficult to distinguish or exclude investment linked to renewable gas.

[x] Department of Climate Change, Energy, the Environment and Water (2025) *Electricity and Energy Sector Plan,* p.6

[xi] Our investment in renewable gas reflects the clear and consistent feedback from our customers. Across both our Access Arrangement consultations and ongoing engagement activities, customers identify renewable gas as one of the most important issues for the future of energy supply. While affordability remains a key consideration, customers also value choice, reliability, and emissions reduction, and expect us to pursue options that support these outcomes. Accordingly, we consider continued investment in renewable gas to be both appropriate and necessary to meet customer expectations and support the energy transition. A regulatory approach that prevents or restricts such investment would be inconsistent with the National Gas Objective, which seeks to promote efficient investment in energy services for the long-term interest of consumers, including through reliability, security and emissions reduction. .

[xii] Australian Energy Regulator (2024) *2024 Electricity and gas networks performance report.* Available at:

https://www.aer.gov.au/system/files/2024-09/2024%20Electricity%20and%20gas%20networks%20performance%20report.pdf. The outage statistics reported by the AER include both planned and unplanned events across all gas distribution networks. The reported figure of <0.01 outages per customer per year reflects a national system-wide average, equivalent to roughly one outage per customer every 100 years. This includes scheduled maintenance works as well as unplanned interruptions. Individual experiences will vary by network and location, and the figure should be interpreted as an indicative measure of overall system reliability rather than a guarantee of service continuity.

[xiii] Rule 91(1), *National Gas Rules* (2025).

[xiv] Crew, Michael A & Kleindorfer, Paul R, (1992) *Economic Depreciation and the Regulated Firm under Competition and Technological Change*, Journal of Regulatory Economics, Springer, vol. 4(1), p. 51-61.

[xv] Crew, Michael A & Kleindorfer, Paul R, (1992) *Economic Depreciation and the Regulated Firm under Competition and Technological Change*, Journal of Regulatory Economics, Springer, vol. 4(1), p. 51-61.

[xvi] Both the ECA and JEC proposed primary rule changes operate in similarly, by limiting the circumstances in which depreciation can be varied. The main difference is that the ECA proposal would prevent a network from recovering invested capital as a condition of changing their existing depreciation schedule, while the JEC proposal would also allow the regulator to declare an asset *may* become redundant in future and allocate the costs of that redundancy between the network and consumers.

[xvii] *National Gas Law,* s24(2)

[xviii] *National Gas Law,* s24(3)

[xix] *National Gas Law,* s24(5)

[xx] *National Gas Law,* s24(6)

[xxi] *National Gas Law,* s24(7)

[xxii] Rule 42(1)(b), *National Gas Rules* (2025).

[xxiii] *For example, the purpose matters; if the report is to be benchmarked against regulatory benchmarks, then the relevant denominator is the RAB, and some aspects of the accounts need to be re-done as though the actual entity is the benchmark efficient entity, but if the report is to be benchmarked against firms in the market at large which are not regulated, then standard accounting must be used. Working through these methodological distinctions in an open and transparent manner took several months and required direct engagement to ensure a shared understanding of perspectives.*

[xxiv] Rule 42(1)(b), *National Gas Rules* (2025).

[xxv] Australian Energy Market Commission, (2025) *Consultation Paper Gas networks in transition,* p. 45-46. Available at: https://www.aemc.gov.au/sites/default/files/2025-09/Consultation%20paper%20-%20GRC0082%20-%20Gas%20networks%20in%20transition.pdf

[xxvi] Australian Energy Market Commission, (2025) *Consultation Paper Gas networks in transition,* p.45.

[xxvii] Australian Energy Market Commission, (2025) *Consultation Paper Gas networks in transition* p.46.

[xxviii] *National Gas Law,* s23.

[xxix] *National Gas Law,* s72A.

Australian Gas Infrastructure Group

# Attachment 1

## The Economics of Asset Stranding

**October 2025**

Dampier Bunbury Pipeline

Multinet Gas Networks

Australian Gas Networks

Australian Gas Infrastructure Group

# Contents

Australian Gas Infrastructure Group

# Overview

This attachment covers two key issues which sit at the core of the proposed rule changes focussed on depreciation (referenced by the AEMC as GRC0082 and GRC0088) put forward by Energy Consumers Australia (ECA) and the Justice and Equity Commission (JEC). These are:

- The rule changes are focussed on the wrong problem, focussing on physical, rather than economic asset stranding.
- The proposed remedies, particularly the change in approach they force upon regulators, are contrary to well-understood, good regulatory economic design and practice and are likely to have serious and significant ramifications well beyond the gas sector.

That is, the proposed rule changes misunderstand what the problem is that regulation needs to address and then propose a solution which would substantially undermine the integrity of economic regulation in Australia.

The economic regulatory framework already, by design, contains the tools necessary to deal with the issue of economic asset stranding, and in this attachment, we outline one potential way in which this could be done.

Section 1 of this attachment covers the framing of the problem by the proposed rule changes. Section 2 deals with what we see as the actual problem which regulators need to address and how the existing National Gas Rules (NGR) have evolved to deal with it. It closes with a practical example of how the existing NGR can be used to deal with the issue effectively. Section 3 covers the unintended consequences of the proposed rule changes.

This attachment should be read in conjunction with our responses to the specific questions the AEMC asks. Our responses to the AEMC's questions draw upon aspects of this chapter to address specific issues.

# 1 Framing the Issue as Outlined in the Proposed Rule Changes

The proposed rule changes consider that the root cause of problems which require a change to the NGR is physical asset stranding. That is, at some point in future, demand for gas will inevitably decline to the point where there are no customers left (or at best, leaving only a limited role serving hard-to-electrify industrial users. The proposed rule changes focus primarily on residential customers and give limited consideration to the needs of business and industrial consumers).

As presented, the proposed rule changes appear to regard the contraction of gas networks as both inevitable and, in some respects, desirable. The argument underpinning the proposed changes can be summarised as follows:

- Demand destruction for gas networks is an inevitable consequence of changes in climate policy which preclude the use of natural gas in the economy (both proponents of the proposed rule changes make it clear they do not believe renewable gas will achieve meaningful scale).
- The end point of this demand destruction will be networks shutting down entirely where they serve residential customers, under current depreciation schedules, when networks shut down, there will be some residual of the RAB which is not recovered.
- Networks are changing depreciation schedules in an attempt to shift the costs of this unrecovered RAB onto customers, who are not being given a say in this.

The proposed rule changes appear to interpret the *regulatory compact* as a fixed, one-off transaction between networks and consumers. Once assets were approved and invested in, consumers undertook to repay those investments over a set period, and any later adjustment to that repayment period represents a departure from the original 'deal'. If conditions in the energy sector have changed, and networks now want to change the timeframe over which assets are paid back, then networks should bear a cost for proposing a change, rather than assuming they have a free option for change.

This position is reflected in statements by Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC). The ECA argues that networks have long been aware of emissions reduction commitments and therefore should have foreseen the impact of climate policy on gas demand (p.19). It also proposes that consumers should not be "unavoidably exposed" to higher prices from accelerated depreciation, suggesting that networks demonstrate shared cost through asset write-downs. Similarly, the JEC argues that network companies are best placed to bear asset stranding risk because the policy environment has been clear since the 1980s and 1990s, making such risks "entirely foreseeable."

We do not accept this characterisation of the problem. In particular:

- We do not believe that physical asset stranding is the problem that economic regulation should focus upon, but rather that it should focus on economic asset stranding (see discussion in Section 2).
- We do not accept the view that networks, by seeking to change depreciation schedules, are shifting risk onto customers. No depreciation proposal has resulted, or could result, in customers paying more for the assets that serve them. Rather, networks are seeking to maintain the balance of risk between themselves and customers as markets evolve. (see Section 2.4).
- The NGR *does not* require, nor was it ever *intended* to require, that economic asset lives remain fixed once investments are made, or that any change to those lives must be accompanied by a write-down of the RAB. We discuss this in Section 2.3.2
- Nor *should* the NGR require that asset lives be fixed once investments are made, or that any adjustment must be 'paid for' by the party proposing it. Such an approach would lead to inefficient outcomes and higher costs for consumers. We discuss this in Sections 3.1 and 3.2.

We turn to our framing of the problem, centred on economic asset stranding, in the following section. Before doing so, it is important to note that Australian gas pipelines have some of the longest asset lives in the world and that previous regulatory decisions have allowed some of the lowest allowed rates of return globally.[1] Both factors contribute to lower prices for customers.

Neither outcome could be sustained if asset lives were fixed, or if changes to those lives required the removal of part of the RAB. Such conditions would expose investors to substantial market risk over multiple decades. Instead, the ability in the NGR to change asset lives was part of a package of elements in the NGR (see Section 2.3.2). Unravelling one part of the package in isolation in the

way proposed in the rule changes will not lead to lower prices for customers, but significant disruption and higher prices in the industry; an issue we return to in Sections 3.1 and 3.2.

### 1.1. AEMC's Approach to Framing the Issue

For their part, the AEMC has not simply accepted the description of the problem as set out by the proposed rule changes. The AEMC define the asset stranding issue as follows (consultation paper, p7):

> *For gas distributors, the prospect of declining demand can also increase the risk that they may not fully recover the capital costs associated with assets that they have efficiently invested in. This could be because there are no, or too few, consumers to feasibly charge to recover those costs. Several gas distributors refer to this as the risk of asset stranding. The Commission uses the term 'stranded' or 'stranding' throughout this paper to refer to unused or underutilised assets for which a regulated business is unable to recover a full return of and on capital.*

This reflects the first part of the quotation from the AER's 2021 *Regulating Gas Pipelines Under Uncertainty* paper which we reproduce on page 6 below. It captures the fact that it is not simply unused assets (or physical stranding) that matter, and the importance of the inability to recover a full return of and on capital in understanding the problem. However, it omits the second, equally important element of the AER's problem statement – the impact of competition from electricity and government policies on customers' willingness to pay, and how these factors contribute to unrecovered RAB. This is the core of economic asset stranding which we address in Section 2.1. Before doing so, it is necessary to clarify the role of demand in understanding this issue.

Demand is important, but as a potential signal in respect of the underlying problem of economic asset stranding. An asset may become economically stranded even if demand remains stable – for example, if the price of substitutes falls such that the regulated network must charge below the regulatory building block price to retain customers, and is successful in doing so. Alternatively, demand may decline significantly, yet remaining customers may still be willing to pay prices sufficient to recover the RAB; for example, if gas is the only option during dunkelflaute events, gas-fired generators may be prepared to cover the full cost of maintaining a pipeline, even if it operates infrequently and only transports relatively small volumes of gas. Demand therefore provides an incomplete signal of the problem; price, being both the price of the gas transportation service and the price of potential substitutes (formalised in the model of Crew and Kleindorfer which we discuss below), is also crucial.

# 2 AGIG's Approach to Framing the Issue

We consider that the correct framing of the issue to which regulation must respond is economic asset stranding, not physical asset stranding as assumed by the proposed rule changes.

In this section we outline what economic asset stranding is and why it, not physical asset stranding, is the problem regulators need to address. We also set out how the NGR already deal with economic asset stranding effectively and describe an approach under the current NGR that can achieve the price outcomes sought by the proposed rule changes. We spend some time on this topic because we believe that a clear understanding of the relevant problem is an essential first step in deriving an appropriate solution.

## 2.1. Understanding Economic Asset Stranding

Economic asset stranding has a simple and rather narrow meaning. Under current arrangements, the prices which "bind" – that is, the prices which networks charge – are those determined by the regulatory building block model. However, as the energy market evolves, situations may emerge whereby consumer willingness to pay falls below the regulatory building block. This may occur due to shifts in relative prices such as a reduction in the price of substitutes for gas or an increase in the cost of gas transport.

Where this happens, the network would not cease operations (except in extreme cases where prices could not cover even operating costs) but instead would set charges based on willingness to pay not building block costs. Revenues will then not be sufficient to recover the efficiently incurred costs embedded in the RAB. The difference between revenue determined by willingness to pay and revenue required to recover efficient costs, expressed as a net present value, represents the quantum of economic asset stranding – that portion of the RAB which will not be recovered when prices fall below efficient costs.

Unlike physical stranding, which affects specific assets such as pipes or valves, economic stranding is a system-wide characteristic of the network. The JEC proposal in particular, overlooks this distinction, tying depreciation adjustments only to the forecast redundancy of individual assets. The concept of economic asset stranding, was first formalised by Crew and Kleindorfer, who note:

> *Section 2 provides an optimization model which illustrates the rather general applicability of the concepts of economic depreciation and relates these to competitive firms, to the RoR firm facing technological progress, and to the price-level regulated firm. It is shown that, under conditions of competition and technological progress, front-loading of capital recovery is essential if the regulated firm is to remain viable. In addition, if the introduction of accelerated capital recovery is delayed by regulators, they may effectively vitiate any opportunity of the firm to recover its invested capital. The breathing space, or period of time, that the regulators can delay introducing the application of efficient capital recovery without ultimately compromising the firm's ability to recover its invested capital is called the "Window of Opportunity" (WOO). This same window of opportunity requires that the level of depreciation initially be set optimally. There are limited opportunities in the future, under technological change and competition, to rectify mistakes made now. Thus, in the case of price-cap regulation, if depreciation is set solely based upon the status quo, the initial price cap may be set at too low a level to allow full capital recovery.*[1]

Their work built on, and in part challenged, Schmalensee (1989) who had suggested that depreciation speeds are invariant to one another (that is, provided that the regulator sets and the firm is able to earn its cost of capital, one depreciation schedule is as good as another).[2] Crew and Kleindorfer showed that this outcome holds only under restrictive conditions, such as when there is no prospect of any forces driving customer willingness to pay below the regulatory building block price. Their analysis focused on identifying the point at which regulators can no longer feasibly act to enable a regulated firm to recover their efficiently invested capital – the Window Of Opportunity PaSt or WOOPS point. The paper is a clarion call for regulators to act, as the authors note (our context in brackets below):

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[1] *Crew, M and Kleindorfer, P, 1992, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", Journal of Regulatory Economics, 4(1), 1992, pp51-61, available here.*

[2] *Schmalensee, R. 1989. "An Expository Note on Depreciation and Profitability Under Rate-of-Return Regulation." Journal of Regulatory Economics 1(3): pp293 -298, available here. This in itself suggests some caution in assuming that current depreciation schedules should be afforded some kind of special status, even absent of major market changes.*

*These (the regulatory impacts of their research) are that regulatory authorities can act in a penny-wise, pound- foolish manner with respect to capital recovery; attempts to decelerate capital recovery, when anticipated by the regulated firm, lead to under-investment, cost increases, and welfare decreases. They may also lead to viability problems for the firm to the extent that competitive forces become the driving force in pricing, thus pre-empting regulatory capital recovery pricing trajectories.*[3]

This paper entered the realm of Australian regulatory practice in a discussion paper from the ACCC and AER, which sought to cover the fifty most important papers in regulatory economics. The paper made the following point:

*A further piece of the jigsaw on depreciation/amortisation was suggested by Crew and Kleindorfer. This paper focused on the possibility of an external constraint on the ability of the firm to recover its costs in the future.*

*Greenwald noted that the regulatory asset base could not increase above the present value of the future revenue stream for an unregulated monopolist. In the Crew and Kleindorfer paper, the present value of the future revenue stream for the unregulated monopolist is declining exponentially over time, perhaps due to forces of competition or technological change. This places a declining upper limit on the path of the regulatory asset base over time. The result, unsurprisingly, is that front-loading of capital recovery is essential if the regulated firm is to remain viable.*

*In essence, when the regulated firm will be constrained by other forces in how much it can recover in the future, the regulator must take this into account in the present and allow the firm a higher rate of depreciation. This is the origin of the tilted annuity concept used by some regulatory authorities in telecommunications regulation. Crew and Kleindorfer point out that traditionally there has always been a sense among regulators and utilities that problems could be put right "at the next rate case". However, they emphasise that this is clearly not always true. If some other constraint – such as changes in demand or technology – prevents the regulated firm from earning a normal return in the future, the regulator must take that into account in its depreciation policy today.*[4]

The notion of economic asset stranding also underpinned the 2021 paper from the AER from which the AEMC derives its own definition that we quote on page 3 of this submission, which notes that:

*Economic stranding of assets is caused by a change in relative costs or prices. It refers to unused or underutilized assets to such a degree that the owner cannot recover a full return of and on capital. It is distinct from physical stranding, which refers to an asset that ceases to be used because of reasons such as obsolescence, failure, damage etc. The regulatory framework allows for assets to stay in the RAB even if they have become physically stranded, although there are provisions in the NGR to allow the exclusion of a redundant asset that is no longer used from the RAB.*

*Provided that customers can switch from gas with little or no transaction cost, end-user gas prices (which includes gas access prices amongst other things) would be constrained by customers' willingness to pay for gas and/or the prices offered by competitive gas substitutes such as electricity. If the constraints on gas prices become sufficiently strong such that gas becomes relatively uncompetitive, then with falling demand, regulated revenues for regulated businesses may not support full cost recovery of the RAB. In this scenario, the network business will under-recover the amounts it has invested over the life of its assets, including a normal rate of return on those capital investments.*[5]

This understanding of economic asset stranding underpins the depreciation approaches adopted by both the ERA and AER. AGIG has applied this framework across multiple Access Arrangement proposals, including the Dampier to Bunbury pipeline in Western Australia in 2021 (here) and 2026 (here), our Victorian AGN and Multinet networks in 2023 (see here and here respectively) and most recently in our proposal for our South Australian network (here). The first of these proposals contains the most direct link to the Crew and Kleindorfer paper cited above, with each subsequent proposal refining our methodology for assessing when and how

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[3] *Economic Depreciation and the Regulated Firm under Competition and Technological Change, p58*

[4] *Biggar, D, 2011, The Fifty Most Important Papers in the Economics of Regulation, ACCC/AER Working Paper No. 3, May 2011, p21, available here.*

[5] *AER, 2021, Regulating Gas Pipelines Under Uncertainty, Information Paper, November 2021, p26, available here.*

depreciation should change to maintain efficient capital recovery. Other networks have put forward similar arguments in their own Access Arrangement proposals.

In closing, it is important to make three points.

Firstly, as the AER recognises, economic asset stranding is distinct from physical asset stranding. The AEMC should likewise follow the AER in making the distinction clear.

Secondly, there are many potential causes of economic asset stranding. In Crew and Kleindorfer, the authors posit competitive forces and technological change lowering the cost of substitutes. However, any exogenous force which results in regulatory building block prices being higher than customer willingness to pay produces the same result. For example, since network costs are largely fixed, a policy which forces customers off the network, pushes regulatory prices up, giving rise to the same effect as would occur if the price of substitutes fall, since it is relative prices which matter.

The third and final point is important when considering how regulation should respond to economic asset stranding. Economic asset stranding can be understood as the point at which economic regulation reaches its practical limit — a concept made explicit in Crew and Kleindorfer's WOOPS point. The AER and ERA regulate networks by setting a price, and if that price no longer binds us, the regulator's ability to influence market outcomes effectively ceases.[6] Any rule intended to address economic asset stranding must therefore operate within the boundaries of regulation itself. In practice, this means that it requires regulators to act early, even when information is uncertain; a point well recognised by both the ERA and AER.[7]

### 2.2. Economic Asset Stranding as the Key Challenge

There are several reasons why economic asset stranding, rather than physical asset stranding, is a more appropriate focus for economic regulation.

Firstly, economic asset stranding will occur sooner. To see this, note first that every good or service, including gas transport has a substitute available at some price; market power is a function of relative prices and not an absolute condition. The price of the substitute sets the upper bounds on consumer's willingness to pay for gas, and by extension gas transport. Under current market conditions, the prices of gas substitutes are generally well above the price of gas delivered through our networks, which is one reason we are regulated, but that need not always be the case. In particular, because networks costs are largely fixed, a decrease in demand leads mechanically via the regulatory building block model to an increase in price. If the decline in demand is sufficient (or, equivalently, the price of the substitute falls) then the price of gas will reach the ceiling of customer's willingness to pay.

No network would passively allow prices to rise unchecked simply because a regulatory pricing model dictates it. Rather, to avoid the total loss of the business and all previously sunk investments, a prudent operator would price to match willingness to pay so long as, doing so, covers ongoing expenses. In this situation, the network will be in a case of economic asset stranding, and it might be decades before the assets are physically stranded physically, if they become physically stranded at all.[8] Regulators planning for the sector's most likely future should therefore prepare for economic asset stranding and how best to protect the long-term interests of consumers under this risk, rather than for a physical asset stranding that may never eventuate.

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[6] *In reality, the world is not as black and white as this. Customers are heterogeneous and it is likely that some would find alternatives to network-delivered gas at a lower price than is reflected in our building block prices before others. So they would be able to emerge from the protection the regulator offers before others. Where this happens, the regulator's role shifts from protecting all customers via a single instrument to offering targeted protection to those customers still subject to market power and allowing competition to drive the remainder of the market. Railways are one example of an industry which is regulated in this way.*

[7] *ERA, 2021 Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2021 to 2025, April 2021, [1510 to [1518] (note, the proposal to seek a rule change on depreciation is mentioned at [1527]), available here, and AER Regulating Gas Pipelines under Uncertainty, Information Paper, p44.*

[8] *By way of an example from a completely different sphere, consider the Eerie Canal, which was completed in 1825, just before the railway boom which rendered it largely superfluous in respect of its originally intended purpose. The canal did not, however, become physically stranded. It may have been economically stranded in the context of a building block model (something which did not exist in 1825) and the prices it would produce but it continued to adapt and change its markets, and, as this article suggest, is still doing so. A rule maker like the AEMC, writing rules to deal with the physical stranding of this asset circa 1840 when the threat of railways first became apparent, would still, 200 years later, have a set of rules which would have no real application. A rule maker focusing on economic asset stranding, could have set them to work almost straight away.*

Secondly, economic asset stranding is a smaller and more manageable problem. A network facing economic asset stranding will continue to operate in order to recover at least some of its previously recovered investment. The losses are therefore limited compared with physical stranding, where the entire RAB may be unrecovered. Regulators who frame the issue solely as physical stranding, risk overstating the scale of the problem. This, in turn, impacts the efficiency of any measure the regulator takes.

Thirdly, economic asset stranding is an explicit recognition of the limitations of any "guarantee" that regulators can make. Crew and Kleindorfer's WOOPS model makes clear that regulators face limits in the actions they can take and that they must act while they can still influence capital recovery. Networks themselves recognise that regulation has limits and incorporate this into their decisions as a matter of course. Regulation should likewise recognise its own limitations.

The proposed rule changes suggest that, absent of regulatory action, prices for customers who remain connected to the network will continue to rise indefinitely as demand falls and that networks will continue to invest in inefficient capital spending unless constrained by stricter regulation.[9] Both propositions are doubtful once the role of economic asset stranding in network decision making is understood.

Whilst customers will exit the network at different times depending on their ability and desire to continue to use gas, all will eventually face a point where they are unwilling to pay more for gas. Prices therefore cannot rise without limit. Networks, aware of this dynamic, will act to retain customers, and so will set prices that reflect willingness to pay—provided those prices meet ongoing operating costs—in order to retain as many customers as possible.[10] All customers will benefit from this dynamic, including those that face barriers to switching.

This means both that prices will not simply rise because the regulatory building block says they should, the basic point of the Crew and Kleindorfer model, nor will networks continue to sink capex on the assumption they will always be able to find a customer from whom to recover it.

A focus on economic asset stranding acknowledges the existence of multiple possible futures. The energy sector may evolve along various potential pathways, each with differing customer bases and levels of willingness to pay. More importantly, a framework centred on economic rather than physical stranding enables to preserve the flexibility networks and their customers need to adapt to a changing world.

By contrast, physical asset stranding is, by definition, a single outcome that varies only in timing. This narrow framing risks creating rules that may fail entirely if the future trajectory of the industry differs even slightly from the specific shut-down scenario envisaged. More critically, it could bring about such an outcome by virtue of the incentives it provides regulators, investors, and customers (see Section 3). Rules that create self-fulfilling prophecies do not meet the threshold test of contributing to the achievement of the NGO.

### 2.3. How the NGL and NGR Deal with Economic Asset Stranding

In this section we provide a brief summary of the development and intent of the National Gas Objective (NGO), the Revenue and Pricing Principles (RPP), and Rule 89(1), in order to provide for the flexibility to deal with changing market conditions. Further detail is provided in the attached expert report from Incenta Economic Consulting ('Incenta') which includes contemporaneous statements from regulators and policymakers involved in drafting to highlight their original intent regarding depreciation.

Incenta identifies RPP(2), which provides for a "reasonable opportunity" to recover efficiently invested capital, as the core principle underpinning the framework. This clause is consistent with regulatory practice globally, reflecting the nature of regulated infrastructure investment characterised by high sunk costs, long timeframes for recovery and exposure to future uncertainty. On the question of what constitutes a "reasonable" opportunity (a point of debate in the current process), Incenta make it clear that this intent of the original drafters of the NGR was to acknowledge the inherent limits of prediction over long time horizons, rather than to narrow the principle itself. In other words, while recovery cannot be guaranteed, there was no intention to limit recovery to

[9] *See pp10-11 of the ECA's rule change proposal on depreciation for the former, and the AEMC's summary of the proposals to restrict capex made by the proponents in pp15-19 of the consultation paper for the latter.*

[10] *This does not mean that all customers will be shielded from price pressures; price sensitive customers may still face prices higher than they would prefer. Such outcomes are inevitable to some degree and would likely be exacerbated once the additional risks created by the proposed rule changes are reflected in prices.*

circumstances in which doing so would restrain price increase. Such an interpretation would effectively negate a foundational principle of utility regulation.

Incenta form the view that the proposed rule changes would have a deleterious effect on the incentive and capacity for future investment in the sector because investors would factor in the risk that the capacity to recover cost might be further limited in the future. Consequently, the proposed rule changes would not advance the long-term interest of gas consumers as required by the proposed rule changes would not advance the NGO.

In respect of Rule 89(1), which governs how depreciation schedules are to be set, and adjusted, Icenta highlights that flexibility was integral to policymakers' original decision. Drawing on statements by the Victorian Office of the Regulator-General prior to privatisation, Incenta notes that policymakers recognised the need for depreciation schedules to adapt to market conditions and for governments to credibly commit not to expropriate investment when conditions changed. The ORG observed that when economic asset stranding becomes a possibility, regulatory depreciation may diverge from true economic depreciation and should be adjusted accordingly. The ORG also emphasised that regulators should be prepared to modify depreciation methods rather than rely on fixed rules and, given the inherent risks, should err on the side of allowing regulatory depreciation to exceed rather than lag behind true economic depreciation. This demonstrates that the ability to adjust depreciation was embedded in the regulatory compact from the outset.

Finally, in relation to Rule 85, which addresses physical asset stranding or redundancy, Incenta notes that the provision was intended to create incentives for networks to improve asset utilisation—not to remove underused assets from the RAB. In practice, the rule has been used sparingly, as such incentive mechanisms are complex to design and have largely been supplanted by more effective tools within the broader price cap framework.

Further details of Incenta's expert opinion on these matters, are provided in the report in the appendix to this attachment.

### 2.4. Addressing Economic Asset Stranding under the Current NGR Framework

As we note above, not only does the NGR allow for depreciation to change, but the ability to make changes has, and continues to be, in the long run interests of consumers. However, the regulator's approach towards determining how much depreciation to allow in a given regulatory period has some limitations.

There is a clear need to translate the NGR's intent to provide networks with a reasonable opportunity to recover efficient capex into a practical solution for determining the extent of change appropriate considering depreciation profiles in each Access Arrangement period. This section outlines a practical approach to achieving this, drawing upon our most recent AGN SA proposal (see here, pp16-19).

Underpinning our approach is the view that the most appropriate way of assessing a depreciation profile under the existing NGR 89(1) is to preserve the balance of risk between networks and customers that was established when the regulatory compact was first formed as conditions in the energy market change. In practice, this means considering how depreciation settings can be adapted to reflect changes in market conditions while maintaining the NPV=0 framework that originally underpinned the regulatory compact.[11]

This does not mean that each stakeholder's level of risk remains fixed. If total risk in the energy sector changes maintaining an identical level of risk for one party would necessarily shift risk onto or away from another. Rather the objective is that each stakeholder continues to bear the same proportion of overall risk as when the regulatory compact was first established, even as the absolute level of risk in the market changes.

In relation to depreciation, the explicit flexibility in the NGR—and its predecessor the Gas Code— to respond to potential economic stranding in advance has always been a fundamental principle underpinning investment in the sector. Nevertheless, networks have always borne some risk of market-driven non-recovery where changes occur too rapidly to respond.

Within this framework, the regulator would begin to act when it perceives a material shift in risk, rather than waiting until the WOOPS point, when regulation ceases to be effective and only partial recovery of the RAB is possible. Focusing on the balance of

[11] *If the compact did reflect an ideal that depreciation should never change in response to market conditions, then investors would expect to only be able to maintain their NPV=0 standing if asset lives were relatively short or the discount rate was much higher. This would have led to higher prices over the past 25 years.*

risk provides an earlier and more reliable signal of when intervention is necessary, avoiding the potential for delay. When market conditions begin to impose a greater share of risk on one stakeholder this indicates that a reassessment of depreciation may be necessary. The framework is intended to operate symmetrically; if customers are assuming more risk, for instance, then depreciation may need to slow). This focus on relative risk offers a timelier and more informative guide than metrics such as demand alone, which may fail to capture underlying shifts such as a sustained decline in the price of alternatives.

### 2.4.1. A Practical Framework for Addressing Economic Asset Stranding

Maintaining relative risk balances may seem conceptually abstract, but it can be expressed in practical terms through a three-part framework.

A network operator, who identifies the potential for a possible decline in demand or the emergence of competitive forces that could result in economic asset stranding, seeks new, sustainable sources of demand to utilise its capacity, in just the same way as a competitive firm would. Regulators, recognising the long-term benefits of competition for consumers, support this behaviour.

Customers of regulated services whether existing or new, accept that these future opportunities may not fully recover the capital expenditure incurred to serve their needs, and that regulators may adjust prices now to address this shortfall. As customers also recognise that ongoing growth in regulated services cannot be assumed, they cease imposing costs on one other as they enter or leave the energy network; and instead bear the costs attributable to assets specific to their own use.

So, if a network has a RAB of $1 billion now, and a reasonable assessment of its value in, say, 2050 under new market conditions where regulatory prices are not the main binding force is $500 million, then between now and 2050 only $500 million would need to be recovered. That is the amount by which the RAB would need to be reduced in order for the network to be price competitive and able to recover its investment from future markets.

By contrast, a position whereby all of the RAB needs to be recovered under regulation, for example, because recovery in a competitive market in the future is not possible, would lead to much more recovery of the RAB more quickly.

Additionally, the third point highlights the fact that depreciation is not the only tool; a decision to allocate private connection costs to those who wish to connect ensures that risks associated with new connection are allocated to those who are best placed to handle those risks; the connecting consumers.

We note that our three-part framework above *could* result in the same prices for consumers today if the amount of RAB that can be recovered from new future markets is the same as the amount that the rule change proposals would see allocated as a RAB write-down for investors, due simply to the way the building block regulatory price model works.

However, the result in respect of incentives for efficient investment is very different. Under the example set out above, investments signals are maintained because there is a pathway towards being recompensed for meeting the long run interests of consumers whether the network is regulated or not. By contrast, as we discuss in Section 3.1 in more detail, by crystalising the losses which might occur in future into the RAB today, the rule change proposals immediately undermine efficient investment incentives.

There is an additional, practical consideration. Under the approach above, if it turns out that too much of the RAB has been allocated to future competitive markets post, say, 2050 based upon new information that arises at the next AA period, it is very simple to allocate those same costs back again to regulatory customers. That is, the depreciation profile of the network can be assessed and adjusted at each Access Arrangement period as the energy transition evolves, markets change, and more information becomes available. By contrast, the rule change proposals impose losses on investors now by writing down the RAB and these funds are gone, meaning mistakes cannot be reversed.[12]

In closing, we note that our framework and approach do not result in economic asset stranding risk being eliminated. Elimination is not possible because regulation has limits that cannot be overcome with better rules. We consider our approach to be a practical means of working within the constraints of regulation to achieve the best long-term outcome for customers.

[12] *In principle, one could imagine a symmetric mechanism whereby customers repay networks when too much RAB has been written down, but implementing this may be complex, and the proposed rule changes do not put forward such a mechanism.*

# 3 The Unintended Consequences of the Proposed Rule Changes

As we discuss above, the proposed rule changes have mischaracterised the nature of the issues facing the gas sector and, as a result, are seeking to address an issue that does not reflect regulatory or economic realities. Furthermore, the proposed solution would likely result in significant unintended consequences that risk undermining the effectiveness and stability of the regulatory framework. In particular:

- The proposed changes would materially weaken investment incentives and depart from established principles of effective economic regulation.
- The proposed changes may place regulators in a position where adherence to the new rules could conflict with the requirements of the NGL. Even if such conflicts could be resolved, the incentives created by the proposals are likely to generate increased tension among stakeholders and reduce confidence in the regulatory process.

### 3.1. Impacts on Investment and Investor Behaviour

We begin with the consequences for investment. These consequences stem from a fundamental shift in the approach regulators are required to take by the proposed rules. Under the current framework, regulators approve investment on the basis that networks are afforded a reasonable opportunity to recover their efficiently invested capital. While reality could change, and unforeseen events may occur that prevent recovery of efficient investment, the intent is that there will be recovery including a response to emerging events in advance. Under the proposed rule changes, this is no longer true.

Instead, the regulator might make a decision that a regulated network ought to be able to recover the investment it makes today in a 50-year asset on the basis that investment is prudent and efficient. However, under the proposed new rule framework, at the start of the next AA period the regulator could change that view, make a different forecast and crystalise losses now by way of a RAB write-down, in circumstances where the future events causing such losses may or may not occur. In simple terms, at the start of the next AA, the regulator is no longer intending to allow a network to recover its efficiently incurred investment. This is a fundamentally different proposition for investors compared to the status quo, which is not addressed in the proposed rule changes.

Consider an example whereby the regulator approves $100 million of capex in this AA and gives it an asset life of 50 years. Then suppose new information arises about the future evolution of the energy sector which causes the regulator to change depreciation schedules and, at the start of the next AA, use an asset life of 40 years. Customers, as a whole, pay no more in terms of depreciation charges. In any given time period they might pay more, but they pay more for a shorter period of time, so the total is still $100 million.

Compare this with the proposed rule change whereby, at the start of the next AA period rather than (or perhaps in addition to) changing the life of the asset, the regulator determines that $20 million should be written down from the RAB. The network recovers only $80 million of its $100 million and is given no opportunity to recover this elsewhere (as distinct from our proposed framework, discussed in Section 2.4.1). By contrast, consumers, who in this example still plan to use the asset for 40 years, do not pay the full cost of their use. This is an example of a 'free lunch' for consumers, paid for by networks. Although not expressed by the proposed rule changes in these terms, it will be immediately clear to any investor that this is what is proposed.[13]

Writing in the *Handbook of New Institutional Economics*, Spiller and Tommasi note:

> *In this section we contend that the overarching problem driving the regulation of utilities, whether public or private, and thus the issues politicians have to deal with, is how to limit governmental opportunism, understood as the incentives politicians have to expropriate –once the investments are made- the utilities' quasi rents, whether under private or public ownership, so as to garner political support. Institutional environments that are successful in generating regulatory institutions that limit governmental opportunism will be able to also provide successful sector performance. This, by no means, implies that other issues like the exercise of market power, the main topic in the incentives*

[13] *A more formal treatment of the linkages between incentives for investment, information and trade-offs involved in making regulation operable can be found in the well-known regulatory economics textbook, Laffont, JJ and Triole J, 1993, A Theory of Incentives in Procurement and Regulation, MIT Press: Cambridge Mass. The nomenclature is subtly different (and a lot more mathematical) but the issue of regulators changing the terms of any deal ex-poste to capture rents are covered in Section 1.9, and the activities and operation of regulatory institutions are covered in Chapters 15 and 16.*

*regulation literature, or interest group politics, the main topic in the Chicago School of regulation, are irrelevant or of no interest. Instead, our thrust is that what drives institutional design in public utility regulation is limiting governmental opportunism, not allocative efficiency. What drives the implementation of regulatory incentives, on the other hand, is the trade-off between allocative efficiency and distributional issues, given the constraints given by regulatory governance.*[14]

Writing for the World Bank, Kessides notes:[15]

*Infrastructure characteristics also create opportunities for government manipulation (Spiller and Savedoff 1999). Because many infrastructure investments are fixed and sunk, private utilities will continue operating as long as prices cover short-run marginal costs. Thus, once sunk investments have been made, bargaining power shifts from investors to regulators (Hart 1995). At that point governments may impose special taxes, require special investments, control procurement and employment practices, restrict the composition and movement of capital, or lower the regulated prices that utilities can charge for services (box 2.5). Recognizing these risks, private utilities will likely invest less than is optimal—especially in activities with large sunk costs—or demand high risk premiums unless governments can credibly commit to regulatory stability.*

Kessides then goes on to discuss various methods by which governments can show investors their commitment not to behave opportunistically (such as concession contracts and stable and transparent administrative rules around regulation), and the trade-off governments need to make between commitment to investors and flexibility to changes in the market.[16]

Writing for the Inter-American Development Bank, Spiller and Savedoff note the conditions under which governments might be tempted to behave opportunistically in respect of infrastructure investors, noting:

*Governments may find it advantageous to expropriate sunk assets if the direct costs are small compared to the (short-term) benefits of such action and if the indirect institutional costs are not too large. The direct costs of expropriation—either directly or through administrative measures—include reduced investment by other operators in the infrastructure and utilities sectors who will, as a result, consider further commitments as increasingly risky. The institutional costs of such expropriations are to undermine the effectiveness of basic rules and norms of governance by disregarding judicial findings or evading proper, or traditional, administrative procedures. Meanwhile, the government may anticipate short-term benefits in electoral gains or winning parliamentary debates by mobilizing the public around the issues of reducing operators' prices or attacking monopoly suppliers.*

*Thus, incentives for expropriating the quasirents associated with the existence of sunk assets will be largest in countries where direct costs are small, indirect institutional costs are low, and the government's horizon is relatively short.*[17]

The notion of government opportunism is also addressed in the "transaction cost regulation" literature, which takes learnings from the study of the issues associated with practices making contracts in the transaction cost economics literature and applies them to the relationship between regulators and governments on the one hand and infrastructure firms on the other.[18] In particular, Spiller notes that it is not just a two-sided game between investors and governments, but also that other stakeholders have interests which need to be understood clearly when they play a role in the process, noting that:

*A fundamental feature of interest groups as monitors (of the regulatory process), though, is that they are interested. In other words, they are biased. They provide information only when it is to their advantage. That is, the third party (or parties) may behave opportunistically. As it relates to government/utility interactions, interested third parties may have*

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[14] *See Spiller PT and Tommasi M, 2005, "The Institutions of Regulation: An application to public utilities", in Menard C and Shirley MM (eds), Handbook of New Institutional Economics, Springer: Dordrecht NL, p518.*

[15] *Kessides, IN, 2004, Reforming Infrastructure: Privatization, regulation and competition", World Bank and Oxford University Press: Washington, p 101, available here.*

[16] *Ibid p103-109.*

[17] *Spiller, P & Savedoff, W, 1999, "Government Opportunism and the Provision of Water," in Spilled Water: Institutional Commitment in the Provision of Water Services, Inter-American Development Bank: Washington, DC, p8.*

[18] *See Spiller P, 2010, "A Tribute to Oliver Williamson: Regulation – a transaction cost perspective", California Management Review, 52(2), 147,58 available here and Spiller, P 2013, "Transaction Cost Regulation, Journal of Economic Behavior and Organization, 89, 232-42, (available here) for details on the linkages between transaction cost economics more broadly and this specific example involving regulation of infrastructure.*

*incentives to challenge, when by such action they benefit, the "probity" of the interaction, thereby affecting directly the perceived probity of the public agent in charge. Such incentives may exist when third parties compete with the public agent in the political market. Benefits, however, may arise also in the economic sphere. In both it may involve the displacement of the incumbent (and competing) public agent. In the political sphere, the challenge may be deemed successful if because of the challenge the public agent is replaced by an agent related, or more to the liking, of the interested third party. As it relates to the economic sphere, the challenge may be deemed successful if the private party is replaced or the terms of the contract or dimensions of the utility's conduct are changed in ways that benefit the third party. But it is precisely because of competition in the political market that such challenges are particularly dangerous to the private and public agent alike.*[19]

In the present context, the "public agent" would be a regulator such as the AER or ERA, and the "private agent" would be a gas network. These insights are important to consider when we discuss how regulation might be applied if these proposed rules and the conflicts which are likely to arise because of the incentives they offer to all parties.

Given the issues outlined above regarding the harms of regulatory opportunism, it is unsurprising that jurisdictions where the incentives for regulatory opportunism are strong —typically those still developing their governance frameworks—have experienced poor investment outcomes. Outside these proposed rule changes, we are not aware of any jurisdiction that has deliberately sought to increase regulatory opportunism, however, there are several examples where weak governance has allowed it to occur, with damaging consequences for investment. Examples include:

- Troesken, Pashigan, Levy and Spiller and Masten examine cases in the US in the 19th and early 20th Century where (usually) municipal governments signed contracts with private suppliers of gas, transit, telecommunications and water (respectively) offering relatively high prices to encourage investment initially and then reneging on these deals.[20] These cases are closest we can find to the current proposed rules because, although the context is very different, these changes tend to happen after a change in view by the regulatory body, not a defined event that can be objectively seen by everyone. It is noteworthy that we need to go back so far in history to find such examples; modern regulatory institutions have come a long way from their municipal forebears of more than a century ago.
- Kessides looks at cases in Argentina for electricity, Ghana for telecommunications, Kazakhstan for energy and Ecuador for Electricity whereby governments required a significant reduction in late payment fees, imposed a major new tax, reversed promised price increases and refused, over a decade, to set rates which would have allowed the rates of return stipulated in the relevant concession contract (respectively). Kessides presents these as examples of opportunistic behaviours.[21]
- Spiller notes a case in Argentina whereby the water utility had its concession cancelled by the relevant local government after attempts (by the government) to set tariffs at levels lower than the relevant regulatory framework allowed and after the government had used all their formal and informal powers to try and force the change. Spiller goes on to note the impacts this had on investment as risk was increased substantially.[22]
- Estache and Wren-Lewis after providing an example of how a telecommunications project in Mali failed due to weak regulatory institutions and government renegotiation, derive general principles on how better regulatory capacity, commitment to the relevant regulatory compact, better accountability and better financing in less developed countries can lead to significant improvements in both regulation itself and the infrastructure needed by these countries to succeed.[23]

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[19] *Spiller, "Transaction Cost Regulation", pp232-42.*

[20] *See Troesken, W, 1997, "The Sources of Public Ownership: Historical evidence from the gas industry", Journal of Law, Economics and Organization, 13(1), 1-25 (available here), Pashigan, BP, 1976, ""Consequences and Causes of Public Ownership of Urban Transit Facilities," Journal of Political Economy, 84(6), 1239-59 (available here) Levy, B, & Spiller, PT, 1994. "The Institutional Foundations of Regulatory Commitment: A comparative analysis of telecommunications regulation", Journal of Law, Economics, and Organization, 10(2), 201-46 (available here) and Masten, SE, 2011, "Public Utility Ownership in 19th-Century America: The "aberrant" case of water", Journal of Law, Economics, and Organization, 27(3), 604-54 (available here).*

[21] *Kessides, Reforming Infrastructure: Privatization, regulation and competition", p 102.*

[22] *Spiller, "Transaction Cost Regulation, pp232-42.*

[23] *Estache, A and Wren-Lewis, L, 2009, "Toward a Theory of Regulation for Developing Countries: Following Jean-Jacques Laffont's Lead", Journal of Economic Literature, 47(3), 729-70, available here.*

- Henisz and Zelner (2001) looking at telecommunications infrastructure across 147 countries show how the inability of a government to commit not to expropriate investments once they are made stymies the ability of countries with less developed telecommunications infrastructure to catch up with more advanced countries.[24]
- Begara, Henisz and Spiller (1998), examining international capital flows into electric utility investment find that institutional quality, particularly the ability of governments to credibly to commit to not expropriating investment has a significant impact on the ability of a country to attract investment.[25]
- Henisz (2002), taking a very long-term view from 1800 to the present shows how political and institutional factors are important for investors across a range of different infrastructure types; particularly to provide international capital the comfort that its investments are safe from political opportunism.[26]
- Biglaiser, Lee and Yoo (2025) examine expropriation of foreign owned assets in developing countries and show how this expropriation leads to lower credit ratings and higher borrowing costs for government debt, due to the signals such expropriation sends to international investors about the respect the country concerned has for the rule of law.[27]

### 3.1.1. Revisiting Past Proposals

We note that the AEMC has previously considered similar rule change proposals in 2012, which sought to re-value the RABs of electricity and gas companies based on asset utilisation. Those proposals were less far-reaching than the ones currently under consultation, as they addressed actual rather than forecast underutilisation. We discuss this review further in Box 1, but note, in the context of investment that the AEMC and stakeholders identified:

- That the rule change requests would create a risk of under-investment, in particular in respect of reliability due to the risk that any investment might be optimised out of the RAB in future. By contrast, the AEMC found that the (then) current rules already provided sufficient disincentives against over-investment, and that the presence of NGR 85 alongside the ability of regulators to review the prudency of capex ex-poste provided additional controls on efficient capex. The AEMC ruled that the proposed rules did not meet the RPP.[28]
- The AEMC noted the proposed rules, because they would give rise to a risk of stranding through ex-poste optimisation, which would need to be compensated through a higher rate of return which would increase costs to customers.[29]
- The AEMC later notes that the MEU approach would appear to transfer risk to networks, which would drive up the WACC, because some capex deemed efficient at the time of investment would not be recovered as the RAB was re-optimised after a change in market conditions.[30] We note in the context of the proposed rule changes that the RAB would be re-optimised based on forecast, not observed (as in the 2012 case) changes in market conditions, which will likely increase the required WACC still further.
- The AEMC was also concerned that the regulator would need to consider the degree of utilisation of every asset in the RAB, which would require considerable resources for this task (including auditing of the regulator's work) and there would need to be very clear guidelines created as to exactly how this could occur. All of this, the AEMC was concerned, would add to the

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[24] *Henisz, WJ and Zelner BA, 2001, "The Institutional Environment for Telecommunications Investment", Journal of Economics and Management Strategy, 10(1), 123-47, available here.*

[25] *Begara MA, Henisz WJ and Spiller PB, 1998, "Political Institutions and Electric Utility Investment: A Cross-Nation Analysis" California Management Review, 40(2), 18-35, available here.*

[26] *Henisz, WJ, 2002, " The Institutional Environment for Infrastructure Investment", Industrial and Corporate Change, 11(2), 355-89, available here.*

[27] *Biglaiser, G, Lee, H and Yoo, SH, 2025, "Foreign Asset Expropriation and Sovereign Bond Ratings in the Developing World", Business and Politics, 27(3), 372-94, available here.*

[28] *AEMC 2012, Rule Determination: National Electricity Amendment (Optimisation of Regulatory Asset Base and the Continued Use of Fully Depreciated Assets) Rule 2012, National Gas Amendment (Optimisation of Regulatory Asset Base and the Continued Use of Fully Depreciated Assets) Rule 2012, September 2102, available here, p11-12*

[29] *Ibid, p19-20.*

[30] *Ibid, p22*

regulatory burden.[31] We note in reference to the current proposals that they (the JEC proposal in particular) would likely create a higher burden given that the regulator would also need to maintain forecasts in respect of every asset.

- In response to the MEU's assertion that the Rules were allowing "uncontrolled investment", the AEMC disagreed suggesting that the incentive mechanisms already in place create strong disincentives against over-investment and that, in any event, limitations in the supply of capital and difficulty of raising debt are likely to limit networks.[32]
- Part of the 2012 proposal (see discussion in Box 1) also dealt with continued use of fully depreciated assets. The AEMC considered that the proposed rule would lead to increased utilisation of the assets concerned but questioned whether this would necessarily be efficient. The AEMC goes on to note the complexity for the regulator in implementing the rule, given the requirements for engineering and other assessments.[33]
- In responding to the AEMC's consultation paper, the AER noted the MEU's concerns about how the energy transition might give rise to customers paying for assets which have become underutilised or stranded, but it disagreed with revaluing the RAB as a solution noting the high amount of complexity this would add to the regulatory task, how it might interfere with its own ability to tailor incentives and how it would add investment risk given the whole RAB would be up for reconsideration at each reset. The AER concludes by noting that:

  > *The current energy market framework strikes a particular balance between risk allocation, investment certainty and price outcomes. Clearly, any rule change will shift this balance to some degree. Under the existing framework the risk of under utilisation of network assets resides with consumers rather than NSPs. The AER considers that MEU's proposal would result in a reallocation of risk that may require further regulatory changes in the future*[34]

- Covec, in an expert report written for the AEMC notes that, under the proposal from the MEU, the regulator would be required to first approve assets and then, some years later, optimise some of the approved capex out of the asset base. Noting the potential for legal challenge, Covec also highlights how doing so would undermine a valuable asset which a good regulator has, for commitment.
- In the same expert report, Covec, addressing the contention by the MEU that competitive industries write down asset value where necessary, notes that doing so would require a higher WACC. Covec make the analogy that the higher WACC is the "insurance premium" paid by customers to the regulated firm to compensate it for the risk of asset re-optimisation, and note that, with perfect information, the net result would be neither a gain nor a loss for consumers compared to the (then) status quo of now asset re-optimisation and a lower WACC.
- Covec also undertakes a thought experiment with an asset which once had higher demand, but which now has lower demand and is being considered for re-optimisation. If the network had perfect foresight about the evolution of future demand and the possibility of a future write-down consequent upon demand falling then, at the time of investment, the network would either not have invested at the scale which was originally needed to avoid the write down, which would result in some customers not being served because the infrastructure would have been too small or negotiated a depreciation schedule which would have seen more depreciation recovered during the time when the asset was being more heavily used.

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[31] *Ibid, p20.*

[32] *Ibid, p22.*

[33] *Ibid, p24.*

[34] *The AER's submission to this review is available here. The quotation comes from page 3 of the submission. We note that the AER had also submitted its own rule change proposal to the AEMC at around the same time and suggested that most of the issues the MEU raised could be better addressed through the measures the AER proposed. In its final decision, the AEMC appears to have largely agreed with the AER on this point.*

*Box 1: AEMC 2012 Decision on RAB Optimisation*[46]

In 2011, the Major Energy Users (MEU) group brought a rule change proposal to the AEMC that would require regulators to:

- review the valuation of all assets during the assessment of the RAB so that the value of assets used in the RAB reflects the minimum value necessary to ensure the provision of the services required. The return on assets would reflect assets that are actually used and not on assets that are under-utilised or not used; and
- disincentivise the replacement of an asset that has not passed its useful life and can be used productively for further service.

The first is a significantly milder version of the depreciation proposals currently being put forward by the proposed rule changes. Both have the effect of changing the value of the RAB, with the difference being that the 2012 review intended on making changes based upon actual use, whereas the current rule change proposal intends to make changes to the RAB based upon changes in future use which might happen. The second is a milder version of the ECA proposals on networks to justify any replacement capex. Both were intended to apply to both gas and electricity networks.

The AEMC ultimately decided not to pursue this rule change. As noted in the quotations above, concerns about investment effects were key. In the case of electricity networks, the AEMC decided that a parallel rule change process initiated by the AER to tighten the assessment of capex ex-ante would address the price concerns the MEU had. In the case of gas networks, the AEMC determined that the NGR was already flexible enough to deal with the MEU concerns. In both cases, the AEMC found that the MEU's proposed rules could increase risk to networks and disincentivize investment, that they would add complexity to the regulatory process and that they would require regulators to have too detailed a role in approving network projects and plans.

It is worthwhile to reflect on history subsequent to this 2012 decision, particularly in the context of electricity. Whilst, for many years, there were concerns raised by stakeholders in respect of excess investment, more recently, investment is proposed to expand significantly to meet the needs of renewable electricity generation. Some of this investment is underpinned by government funding, but most is projected to be provided by the public sector. It is worthwhile considering whether the private sector investment the electricity sector now seeks would have been forthcoming if, from 2012, electricity networks had faced the possibility of RAB revaluations. Those considerations are equally apt for the gas sector, which is in a similar place in respect of renewable gases today that the electricity sector was in respect of renewable electricity 15 years ago.

### 3.2. Broader Impacts of the Proposed Rule Changes

The issue of investment concerns also has direct implications for credit rating agencies, whose assessments determine the cost of debt for energy networks. Roughly 30 percent of Moody's credit rating for regulated utilities is derived from its evaluation of two characteristics— "Stability and Predictability of the Regulatory Regime" (15 percent) and "Cost and Investment Recovery (Ability and Timelines)" (15 percent). Table 1 below outlines the criteria Moody's uses to assesses each of these factors.

Australian Gas Infrastructure Group

*Table 1:Moody's Credit Rate Characteristics*[35]

| | Stability and Predictability of Regulatory Regime | Cost and Investment Recovery (Ability and Timeliness) |
|---|---|---|
| ***AAA*** | Regulation is independent, well established (> 15 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are consistently applied, with public or shared financial models). These conditions are expected to continue | No regulatory or contractual impediment to adjust tariffs (no approval or reviews required). |
| ***AA*** | Regulation is independent, well established (> 10 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are generally consistently applied). These conditions are expected to continue. | Tariff formula is expected to allow for timely recovery of operating expenditure including depreciation, electricity losses and balancing costs/shrinkage gas and a fair return on all investment. All capital expenditure is included in asset base as incurred. Unanticipated expenditure quickly reflected in allowed revenue with low, if any, efficiency assessment. |
| ***A*** | Regulation is generally independent and developed (regulatory principles define risk allocation between companies and customers and are based on established precedents in the same jurisdiction). These conditions are expected to continue. | Tariff formula is expected to allow for recovery of operating expenditure including depreciation based on allowances set at frequent price reviews (5-yearly intervals or shorter) and a fair return on all efficient investment. Capital expenditure is included in asset base as incurred. Opex and capex subject to efficiency tests; electricity losses and balancing costs/shrinkage gas subject to efficiency test on volumes only (price is a pass through). Unanticipated expenditure generally quickly reflected in allowed revenue although this may not be until the following regulatory period and may be subject to a degree of regulatory scrutiny or sharing factor with customers. Performance is likely to be in line with regulatory expectations. |
| ***BAA*** | Regulatory framework is relatively new and untested, although regulatory principles are based on established precedents. Jurisdiction has a history of independent and transparent regulation for other utility services. These conditions are expected to continue. | Tariff formula is expected to allow for recovery of operating expenditure including depreciation and return on investment but subject to retrospective regulatory approval or infrequent price reviews (> 5-yearly intervals); recovery of electricity losses and balancing costs/shrinkage gas is somewhat exposed to price. Some instances of revenue backloading expected (e.g. depreciation allowance set below asset consumption or operating expenditure is capitalized). Unanticipated expenditure slow to be reflected in allowed revenue or may be subject to a stringent efficiency assessment / low sharing factor. Performance may be below regulatory expectations. |
| ***BA*** | Regulatory framework is defined but not consistently applied; tariff setting is subject to negotiation and political interference; some precedents in the country of predictable regulation for other utility services. These conditions are expected to continue. | Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas has large exposure to price. Revenues expected to cover most operating expenditure but investment is not clearly or fairly remunerated. Overspend either not recognized in allowed revenue or there is high uncertainty about its future recognition.<br><br>Operational underperformance likely to be significantly impacting the returns achieved by the business. |
| ***B*** | Regulatory framework is unclear, untested, or undergoing significant change, with a history of political interference. These conditions are expected to continue. | Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas is fully exposed to price. Revenues expected to cover cash operating expenditure. |
| ***CAA*** | Regulatory framework is not defined, is unpredictable or politically driven with significant adverse consequences for the utility. These conditions are expected to continue. | Revenues expected to only partially cover cash operating costs. |

[35] *The Moody's rating methodology is available here. S&P is not quite as detailed in its assessment, but it appears to follow much the same methodology when it makes an assessment of whether a regulatory regime is strong or weak (see p148 of the S&P methodology, available here).*

Currently, Australian utilities are assessed by Moody's within the AAA or AA bands for both characteristics. While Moody's evaluates regulatory governance systems as an integrated whole, if these rule change proposals were assessed in isolation, based solely on how Moody's describes its process of assessment, we consider it unlikely they would achieve higher than a B rating. Such a rating would fall well below investment grade (BAA and above).

The impact on the gas sector will be most immediate, with a sharp curtailment in investment, to the bare minimum necessary to keep pipelines operating safely at the lowest level of service quality that can be sustained.

The outcome which the proposed rule changes see as inevitable may become self-fulfilling, driven by outcomes determined by regulation rather than market forces. While this may appear consistent with the views of those who prefer a transition away from natural gas, achieving such an outcome by diminishing investment incentives would be both highly inefficient and outside the regulator's mandate.

The erosion of investment confidence would manifest in several practical ways across the sector. The following examples illustrate how reduced certainty in the regulatory compact would alter network behaviour, distort expenditure decisions, and increase costs for consumers and governments alike.

Many pipeline issues can be addressed through either an operating expenditure (opex) or capital expenditure (capex) solution. While opex measures may provide short-term relief, they are generally more costly over the long term, as they do not resolve the underlying cause. If, however, capex investments are exposed to the risk of regulatory appropriation, networks will rationally favour opex alternatives. This would ultimately lead to higher prices for consumers as the network fades.

Where customers continue to require, or choose gas, and new investment is required to meet that demand (for example, to supply a new industrial facility), networks will be unwilling to fund such investment under regulatory framework where the regulatory compact can no longer be relied upon. Investment would instead proceed through individual contractual arrangements with customers. Increasing costs and ultimately leading to higher prices.

In jurisdictions where governments support renewable gas as a key part of a sustainable energy future, those governments would face the same challenge as industrial customers. With the regulatory compact no longer reliable, governments would need to enter into explicit contractual arrangements to achieve their policy objectives. This would increase costs and reduce the efficiency of policy delivery.

The impacts, however, will not be limited just to gas. Inviting regulators to fall into the trap of appropriating capex once it has been sunk merely because the price increases required to permit cost recovery are inconvenient opens a Pandora's Box for all fixed cost investment, due to the moral hazard concerns it raises for regulatory practice. This is why the economic regulation literature is consistently opposed to such practices. We are not suggesting that Australian regulators would start to act capriciously; they would follow the NGL and the NGR as they have always done.

However, if this rule change is approved for gas, there would be nothing preventing similar proposals in other infrastructure sectors, particularly where the risk of economic asset stranding arises and infrastructure owners seek to adjust depreciation profiles to manage this risk—or simply where cost recovery requires prices higher than decision-makers consider acceptable.[36]

Indeed, investors would not need to look far to see the implications. Major electricity transmission investments necessary for the energy transition involve substantial cost and uncertainty, depending on assumptions about long-term demand and the future generation mix. It is inevitable that some transmission projects will prove less valuable than anticipated, and in 15 to 20 years consumer groups may again be tempted to advocate for write-downs of sunk investment to moderate network prices.

The AEMC's stance in relation to cost recovery for gas industry assets in a context where the market has changed will provide the potential investors in electricity transmission with a strong signal as to how the same issue for electricity transmission may be treated in the future and so have a powerful effect on current investment incentives.

Even if they are not familiar with the lobbyist's activities in the Australian energy space, changes to the Rules— such as the ones proposed—are likely to be perceived by investors as an increase in sovereign risk. The sector is undergoing its largest

[36] *In this context, we note this article, roughly a decade old and written at the time when investment in electricity networks was considered to be excessive, referencing work which appears to suggest that electricity network RABs should simply be halved, to enable them to compete better with rooftop solar and to give customers prices comparable with overseas jurisdictions. We note that the Grattan Institute has also contemplated asset write-downs for the electricity sector in the past (see here).*

transformation in at least a century, requiring tens of billions of dollars of investment. Signals that regulators' decisions may be influenced by such rules could lead some investors to proceed with greater caution at a critical time for energy sector investment.

### 3.3. Legal and Procedural Concerns Arising from the Proposed Rule Changes

The AEMC may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NGO. The AEMC must also take into account the revenue and pricing principles.

In our view, the proposed rule changes would clearly have the effect of discouraging efficient investment and could not be said to contribute to the achievement of the NGO. Further, if regard is had to the RPP, it can be seen that the RPP and NGO cannot be given effect to when applying the proposed new rule framework. The rules as proposed do not meet the AEMC's rule making threshold. We outline these viewpoints further below.

#### 3.3.1. Legal Issues

The National Gas Objective is:

*…to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to:*

*a. price, quality, safety, reliability and security of supply of covered gas; and*

*b. the achievement of targets set by a participating jurisdiction—*

*a) for reducing Australia's greenhouse gas emissions; or*

*b) that are likely to contribute to reducing Australia's greenhouse gas emissions.*[37]

And the Revenue and Pricing Principles say:

*a) The revenue and pricing principles that apply in relation to a pipeline service provided by means of a scheme pipeline are the principles set out in subsections*

*b) A scheme pipeline service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—*

*a) providing reference services; and*

*b) complying with a regulatory obligation or requirement or making a regulatory payment.*

*c) A scheme pipeline service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—*

*i. efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*

*ii. the efficient provision of pipeline services; and*

*iii. the efficient use of the pipeline.*

*d) Regard should be had to the capital base with respect to a pipeline adopted—*

*1. in any previous—*

*1. access arrangement decision; or*

*2. decision of a relevant Regulator under section 2 of the Gas Code;*

*2. in the Rules.*

*e) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.*

*f) Regard should be had to the economic costs and risks of the potential for under and over investment by a scheme pipeline service provider in a pipeline with which the service provider provides pipeline services.*

*7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a scheme pipeline service provider provides pipeline services*[38]

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[37] *National Gas Law 23 available here.*

[38] *National Gas Law 24, available here*

We do not think the AER or ERA could meet the NGO or the RPP and the proposed rule changes at the same time.

In respect of the efficient investment components of the NGO (and RPP), we have covered in some detail in Section 3.1 how the proposed rules do the opposite and will very deliberately discourage efficient investment. The proposed framework would result in poor regulatory governance via the way they mandate the regulatory opportunism that sound regulatory frameworks seek to limit. We find it difficult to understand how this could be consistent with the NGO's requirement to promote efficient investment.

It is also unclear how the NGO's requirements around efficient use of assets or its newer emissions control requirements are promoted by the rule changes. It could be argued that, in a competitive marketplace, firms write down assets all the time, even when those assets are still being used, based on a view towards the future which may or may not pan out. It could also be argued that there is little difference between a firm doing this and a regulator doing it. There is, however, a fundamental difference. In a competitive marketplace, if new information comes about which suggests that the write-down was too severe, or that prices at a given point in time are wrong, the competitive firm can quickly change to return prices to a level which promotes efficiency.

The regulator, under the proposed rules, cannot. Once the RAB is written down, it stays at the written down value, and all future prices will be based on that written down RAB, even if it turns out that the regulator was wrong, and the write-down was excessive.[39] When this happens, because of the way the building block model works, the regulatory prices will be wrong; they will be too low, and they will promote inefficiently high use of the relevant network. To the extent that the proposed rule changes are correct, and increased use of gas is not in keeping with reducing Australia's greenhouse gas emissions, [40]this part of the NGO would also be breached by these proposed rule changes.

In respect of the revenue and pricing principles, the same basic efficiency concerns affect the ability of networks to meet RPP 3, 5 and 7. Specifically:

- Networks cannot promote efficiency with respect to the use of reference services (RPP3) if it is impossible to undo past actions and produce efficient prices.
- A tariff which crystalises the possibility of future asset stranding into a loss today adds a new risk based on action by regulators which is currently not priced and would need to be priced if RPP 5 is to be met. This might be done by changing the rate of return but, as the AER has determined in its 2021 paper, this is a suboptimal way of dealing with the issue.[41] We note also that creating a new risk and then compensating for it is arguably not good practice rule-making when the opportunity not to create the risk exists.
- It is difficult to see how the economics costs and risks of over or under utilisation of a pipeline (RPP7) can be addressed if, as discussed above, networks and regulators are unable to respond to a situation of over-use because past actions have set prices too low.

For RPP 2 and 6, which discuss efficient investment, the discussion in Section 3.1 is as relevant as it is for the NGO as discussed above. Specifically, in the context of these elements of the RPP:

- We cannot understand how a regulator who is required to write down the RAB when the assets involved are still in use (and remain in use through their economic lives), can still be said to be providing a "reasonable" opportunity to recover costs as per RPP 2. As we discuss in Section 3.1, we think the change in intent, forced upon regulators, contravenes RPP 2.
- It is difficult to see how a regulator can have regard to the costs and risks of and under-investment, as per RPP6, when its own actions in following the proposed rules would fundamentally influence investment incentives. There would appear to be a degree of circularity created here which may be challenging to address.

As the discussion above shows, we do not think that a regulator could make a credible case that it is continuing to meet the NGO and RPP as it implements these proposed rule changes.

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[39] *In theory, this could be fixed by customers being required to pay back any "mistakes" in asset write downs, to make the proposed rule changes symmetrical. This, however, would be complex, and the proposed rule changes do not appear to contemplate this symmetry. We note that our proposed approach (See Section 2.4.1) does not suffer this problem because the RAB is never gone, but just moves to another "bucket", from which it can be moved back if that decision turns out to be wrong.*

[40] *See, for example, the ECA rule change proposal, pp7-9.*

[41] *AER 2021, Regulating Gas Pipelines Under Uncertainty, Information Paper, November 2021, pp32-3, available here*

### 3.3.2. Procedural Issues

The impact of the proposed rule changes, if the AEMC determined they did contribute to the achievement of the NGO, on regulatory practice are likely to be substantial due to the incentives both rule changes produce for stakeholders.

As noted above, the asymmetry in the proposed approach means that consumers are given a one-way bet; by construction consumers as a whole can never pay for more than the cost of the invested capital but every "win" they have when the regulator decides to write down the RAB of a network by a certain amount leads to lower prices.

This gives consumers an incentive to continue to lobby for larger and larger write-downs, rather than to accept a particular package of proposals (which delivers a price and an ability for the network to continue operating for a certain number of years with the relevant capex). This is because, for a customer with a short time horizon or, as the AER noted in their 2021 paper[42], who can switch away from gas with little or no transaction cost, there is very little incentive to accept any price that reflects any non-zero RAB value.

Consumers, however, are not homogenous, and do not all have very low transaction costs in respect of switching between gas and electricity. Biggar[43] suggests that a key role for regulators is to protect the sunk costs that consumers have when they decide to invest in network services; for example, the cost of gas appliances. The key point is that as sunk costs differ for different consumers, so to do the transaction costs involved in transitioning away from gas. For example, a residential gas appliance may be expected to last for approximately 15 years, whereas a factory might expect to recover its costs over 30 years, or more.

So, a residential customer will have a very different perspective to an industrial customer, and they may not be able to agree on a joint position. Moreover, even within residential customers with exactly the same gas bundle of exactly the same age, the transaction cost of switching to electricity may be much lower for a wealthier customer compared to a poorer customer, and so even within residential customers, there may be highly divergent views.[44]

We are seeing divergent views already, some consumer groups responding to our recent SA AA proposal argued that we had set depreciation too low (see the SARG submission here), whilst others argued that we set it too high (see the SACOSS submission here). We consider it likely that, in future, if asset write downs were to make a permanent change to prices and a significant change to investment incentives, these differences will become sharper.

Worse, there is no reason to suppose that any conflict between networks and customers, or between different groups of customers who may impose costs on each other by virtue of the positions they take via-a-vis asset write downs, will be limited to the sphere of an AA determination itself, with the regulator as the arbiter. To give effect to an asset write-down, regulators need to make a forecast of how the energy sector might evolve and then crystalise that forecast into a RAB write-down today. The forecast needs to be made in an environment where the future of the energy sector is entirely unclear as the sector is going through generational change.[45] At the same time, the basis of the forecast needs to meet administrative decision-making standards. We believe it will be exceptionally difficult for regulators to do this, not due to a lack of skill, but due to the nature of uncertainty in the energy sector.[46]

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[42] *Ibid p26.*

[43] *See Biggar DR, 2008, "Is Protecting Sunk Investment by Consumers a Key Rationale for Natural Monopoly Regulation?", SSRN Working Paper, available here, and Biggar D and Heimler A, 2021, "Is protecting sunk investments an economic rationale for antitrust law? Is protecting sunk investments an economic rationale for antitrust law?", Journal of Antitrust Enforcement, Volume 9, Issue 2, July 2021, pp 203–243, available here*

[44] *In particular, vulnerable customers, are likely to favour a loss to networks which is smaller, where they need gas for longer, compared to wealthier customers, who can more easily switch away from gas.*

[45] *We discuss this in some detail in our recent SA AA proposal, where we liken the scale of the change to the substantial changes wrought not just on transport by the private car, but also on urban form over the 20th Century, and outline some of the new competitive forces which might emerge in energy to create such change (see here, pp4-15).*

[46] *Changing depreciation schedules also requires forecasts to be made based on high degrees of uncertainty. However, this does not impose losses on any party, which makes all the difference when it comes to challenges to decisions.*

Australian Gas Infrastructure Group

# Appendix 1: Incenta Economic Consulting Report on Depreciation in the NGO and its Historical Development

INCENTA
ECONOMIC CONSULTING

Roxanne Smith
Executive General Manager – Corporate and Regulation
Australian Gas Infrastructure Group

30 October 2025

# Historical background relevant to the rule change proposals

## Introduction and summary

### *Background*

The energy transition is projected to cause major change for regulated gas networks, leading to a high degree of uncertainty about the future demand (both in terms of volumes and consumers) for distribution networks. If the asset lives that are currently applied for regulatory depreciation are maintained, gas networks would not be expected to recover their past investments (as reflected in the capital bases) and so suffer "economic stranding".[1] Shortening asset lives – and raising near-term prices – could see past investments recoverable in full, or at least reduce the extent that past investment that is not recoverable.

The AEMC is considering two rule change proposals that would place conditions on the capacity for gas networks to adjust the asset lives that are applied for regulatory depreciation purposes to address potential future economic asset stranding.[2] One proposed condition is that some amount of economic asset stranding would be left in place – with the shortening of lives either forecast to leave a share of the "no change" asset stranding in place (the ECA proposal), or for part of the capital base to be written off *ex ante* as a condition of shortening asset lives (the JEC proposal).[3]

The rule change proponents argue that this is necessary because the gas regulatory regime never foresaw the potential for gas demand to fall such that a shortening of asset lives – and price increases – would be required for network costs to be recoverable. The proponents also consider that the "capital redundancy" provisions contained in the NGR do not address this situation.

### *Your request*

You have asked that I provide my observations about the thinking that underpinned the provisions of the existing regulatory regime, and what this would imply about the circumstances the gas sector is

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1 The term economic asset stranding refers to a situation where a regulated business is unable to set prices that would permit its full cost (including past investment as reflected in its capital base) to be recovered as a consequence of a constraint arising from outside of the gas regulatory regime.

2 Energy Consumers Council, 2025, Gas Distribution Network Rule Change Requests: Regulatory Depreciation, February (AEMC ref GRC0082); Justice and Equity Centre, 2025, Gas Distribution Network Rule Change Request – Accelerated Depreciation and Redundancy, June (AEMC ref GRC0088).

3 The rule change proponents refer to the "sharing" of stranded asset risks, which is not in my view a meaningful concept. Rather, the outcomes are either that the asset owners are able to recover their costs in full over time, or that costs are not able to be recovered in full and so there is (economic) asset stranding. It follows that the risk of asset stranding is only ever borne by the asset owner.

facing. You have also asked that I provide brief observations about the merits of the rule change proposals.

### *Summary*

The potential for gas distribution businesses to face future constraints with respect to their ability to recover costs was in the minds of the original drafters of the gas regulatory instruments. The gas sector had always faced competition from electricity and referred to gas as a "fuel of choice" (I recall that the effect of reverse-cycle air conditioning on the demand for gas for heating was front of mind around the time the gas regulatory regime was first drafted). Indeed, this consideration explains some of the unusual features that have always been present in the gas regulatory regime, including the capacity to remove price controls where regulation is no longer necessary and, more subtly, the assumption that distributors (rather than developers as is the case for electricity) would be the parties that arrange the installation of gas infrastructure in new subdivisions.

To this end, I confirm that the intention was that the regulatory depreciation provisions would be applied in a flexible manner that would permit costs to be recovered to the extent that this is possible (i.e., given the external constraints from competition and other factors, like policy changes). This intention can be seen in the discussion papers that predated the creation of the regulatory regime, as well as in the early regulatory decisions under the new regime. Ironically, at the time, it was the electricity sector that was considered at more risk of asset stranding, and similar discussions can be found in relation to this sector. From these discussions, in my view, it would be reasonable for regulated network businesses to have formed the expectation that regulatory depreciation would be applied in a flexible manner to head off foreseeable risks to cost recovery to the extent possible.

Moreover, the expectation that depreciation would be adjusted where necessary to permit the recovery of efficient costs was further cemented by a requirement in the law that regulated prices provide a reasonable opportunity for the recovery of efficient costs.[4] I observe that providing the expectation that efficient costs would be recoverable is critical to providing the incentive and capacity for efficient new investment, and that encouraging efficient new investment in turn is a critical component of the advancement of consumers' long term interests, as set out in the objective to the regime.

In relation to the capital redundancy provisions in the current NGR (rule 85), I agree that these do not "deal" with the issue of (economic) asset stranding risks, but this is because they were never intended to. Rather, these provisions were intended to provide regulators with the option to use a form of asset stranding as a means of providing an incentive for increased asset utilisation. However, as it happens, this mechanism was never taken up in a material way because of the difficulties with designing such a mechanism, and because simpler options (i.e., applying price caps) were available.

Turning to the rule change proposals, it follows from the discussion above that:

- the gas regulatory regime already has the flexibility to deal with the challenges to cost recovery presented by the energy transition, and further rule changes (in relation to depreciation) are not required, and

[4] National Gas Law (NGL), section 24(2) (this is the paraphrasing of the first of the Revenue and Pricing Principles). Prior to the passage of the NGL a similar provision was included in the objectives for regulated pricing that were contained in the National Gas Code (section 8.1(a)).

- the proposals themselves would amount to a material change to how asset owners would have expected the regime to operate in the current environment.

In my view, both rule change proposals are inconsistent with the revenue and pricing principles of the NGL as the proposed changes would be inconsistent with providing networks with a reasonable expectation that efficient costs would be recovered. I would expect that both rule change proposals would have a deleterious effect on the incentive and capacity for future investment in the sector because investors would factor in the risk that the capacity to recover cost might be further limited in the future. Consequently, the proposed rule changes would not advance the long-term interest of gas consumers as required by the National Gas Objective (NGO). To be clear, in my view two propositions hold.

- First, it was clearly in the long-term interest of gas consumers in the early days of regulation in Australia for regulators to provide the commitment that efficient costs would be recoverable, and to signal that there would be flexibility over depreciation to this end. This commitment permitted very long asset lives to be applied when calculating regulated gas prices, and has also allowed regulators to avoid the very difficult issue of whether additional risk premia should be applied in respect of the risk of (economic) asset stranding.

- Secondly, maintaining that commitment to recover past costs is in the long-term interests of gas consumers (i.e., the NGO) today because maintaining *past* commitments is critical to encouraging *new* investment, and substantial new investment will continue to be required to provide the services that consumers want during the energy transition.

Indeed, I would expect that a rule change that reduced the flexibility for regulated gas networks to recover costs as market conditions change would also be looked upon unfavourably by investors in other infrastructure sectors, and so potentially have much broader effects. For example, investors in electricity "integrated system plan" projects also face the risk that market conditions may change in the future (for example, that technological change or policy change causes a change to where new generators locate) and that projects that are judged to be efficient today are nonetheless not used to the extent that was forecast. Those projects are currently being analysed on the assumption that there is no risk to the capacity to recover the costs of projects that are prudent and efficient when undertaken irrespective of how the market may evolve.

The rule proponents have highlighted the need to ensure that vulnerable consumers are not left behind during the transition, which is clearly an important objective. However, I do not think this concern is likely to emerge as a real issue in the medium term because gas networks will have an incentive to offer prices that retain as many customers for as long as possible, and the benefits of this strategy will flow through to all customers. If there is a final group of customers that is unable to switch (because of a lack of control over appliance decisions or because the costs are prohibitive for them) then this would better be addressed by through government initiatives.

It also follows from the discussion above that if economic stranding were to occur, this need not require any changes to the regulatory regime or actions by the regulator. Rather, this would simply mean that competition – rather than regulation – would provide the operative constraint to customer prices. Indeed, the appropriate response at that point would be to remove formal price control given that the network would no longer have market power and the cost-based price controls were redundant.

## Elaboration on the above remarks

### *National gas objective and revenue and pricing principles*

The objective of the gas regulatory regime is provided as follows:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to—*
>
> *(a) price, quality, safety, reliability and security of supply of covered gas; and*
>
> *(b) the achievement of targets set by a participating jurisdiction—*
>
> *(i) for reducing Australia's greenhouse gas emissions; or*
>
> *(ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.*

I note that the interests of consumers are defined (non-controversially) to include the price as well as the quality/reliability of provision. I observe that the requirement for consumers' interests to be pursued from a long term perspective means that achieving the ongoing investment required to provide the services that consumers want (i.e., the quality and reliability) is a core concern of the objective.

The Revenue and Pricing Principles provide the instruction to the AEMC (as rule maker) and the AER (as applier of the rules) how the NGO is to be achieved when setting regulated prices. The principles (excluding the introductory provision) are as follows:

> *(2) A scheme pipeline service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—*
>
> *(a) providing reference services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*
>
> *(3) A scheme pipeline service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—*
>
> *(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*
>
> *(b) the efficient provision of pipeline services; and*
>
> *(c) the efficient use of the pipeline.*
>
> *(4) Regard should be had to the capital base with respect to a pipeline adopted—*

*(a) in any previous—*

*(i) access arrangement decision; or*

*(ii) decision of a relevant Regulator under section 2 of the Gas Code;*

*(b) in the Rules.*

*(5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.*

*(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a scheme pipeline service provider in a pipeline with which the service provider provides pipeline services.*

*(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a scheme pipeline service provider provides pipeline services.*

The first of these principles (RPP1) is typically seen as a cornerstone of utility regulation, namely that regulated business should be provided with confidence that costs that have been efficiently incurred will be recoverable under the regulated prices, which in turn is critical to providing networks with the incentive and capacity to invest in regulated assets.[5] The importance of a legal provision of confidence with respect to cost recovery arises because:

- investment typically cannot be reversed or redeployed once made, and so investors will be exposed to the decisions that regulators take over the life of the assets, and

- regulated assets are typically recovered over an extended period (and far in excess of the period over which cost recovery would be expected in a competitive market), and so this exposure to future events – including potentially major changes in markets – will be substantial.

I observe for completeness that this protection that efficiently incurred costs will be recoverable is most important where cost recovery becomes inconvenient, such as in the current circumstances where the energy transition and increasing competition from electricity means that real increases in regulated prices will be required to be consistent with the principle of enabling costs to be recovered. While it is true that the principle in the NGL is subject to the caveat that there should be a "reasonable" opportunity for cost recovery, a reading of the historical materials and good regulatory principles suggests that the "reasonable" rider was intended to:

- allow for the fact that incentive regulation applies under the gas and electricity regimes, so that the recovery of cost is always subject to meeting the forecasts determined by the regulator, and furthermore that the regime cannot provide guarantees for matters that are beyond the control of the regulator, but that

[5] This cost recovery principle is often re-stated by regulators as requiring the (expected) net present value of regulated cash flows to be zero, which is a key criterion for whether an investment (and committing funds to an investment) is commercially viable.

- there was never an intention that the fundamental principle that costs should be able to be recovered would be limited otherwise (for example, that cost recovery would only be permitted where price increases were not inconvenient) – limiting the clause in this manner would essentially nullify any operation of the principle that is a cornerstone of utility regulation.

Many of the remaining revenue and pricing principles add to the meaning of the cost recovery principle, which include:[6]

- emphasising the importance of incentives for investment (as discussed above), as well as the incentive to operating the pipeline efficiently and the incentive to encourage efficient use of the pipeline (RPP2)

- also emphasising the importance of continuity over time in the asset values that are used for regulated pricing (RPP3), which is embedded within the NGR, and

- that the return on capital element that is factored into prices should include compensation for all commercial and regulatory risks (RPP4), which is implicit when regulators have expressed this principle as requiring regulated cash flows that generate an expected NPV=0.

### *Deprecation principles*

The current rules in relation to (regulatory) depreciation are set out in Rule 89(1) and are as follows:[7]

> *The depreciation schedule should be designed:*
>
> *(a)* *so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and*
>
> *(b)* *so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and*
>
> *(c)* *so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and*
>
> *(d)* *so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and*
>
> *(e)* *so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.*

The most relevant principles to the current rule proposals are those set out in (b) and (c), which requires assets to be depreciated for pricing purposes over their economic lives (i.e., the period over

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6 The final two revenue and pricing principles provide guidance for the regulator when deciding how the uncertainty in deriving regulated prices should affect the final prices that are derived, that is, whether the price should be chosen at a higher or lower point in the range. The principles suggest that the economic costs and risks of under- or over-investment, and under- or over-use of the pipeline are relevant to this issue. I do not see this principle as directly relevant to the current rule change proposal.

7 I note rule 89(2) observes that back-ended depreciation may best meet these principles under specific circumstances (namely, where an asset is constructed with substantially more capacity than initially required in order to meet strong forecast growth in demand), which is not the main case at issue here.

which a market for the services provided by the asset will remain) and that further requires these lives to be updated over time as new information on the economic lives of the assets is received. In other words, it is the intent of the Rules for economic lives to change as market conditions change to ensure that networks continue to have a reasonable opportunity to recover their efficiently incurred capital expenditure whilst those assets are being used, and to head-off potential risks by acting in a timely manner before external constraints place a material limit to cost recovery. Given that asset lives of up to 80 years have been applied for gas assets, it is to be expected (rather than exceptional) that one of any number of events could occur over that life (i.e., changes in operational performance, technology, the market and/or the policy environment) that would warrant a revision to the remaining economic life of the asset.

This idea that depreciation would be flexible and varied over time as necessary to ensure that a reasonable opportunity remains for efficient cost to be recovered has been emphasised by statements of regulators, including those around the time the new gas regime commenced, and used as a justification for not providing compensation for the risk that would otherwise be borne (i.e., if excessively long asset lives were retained as market circumstances changed). For example, the Victorian regulator (then the Office of the Regulator General) commented on the role of depreciation as a means of addressing potential economic stranding as follows:[8]

> *The competitive market paradigm provides a useful reference point for considering Depreciation methodologies. In a competitive market, if an investor thought that an asset bought in this period would be made redundant in the next period by a technological advance, then the investment would only take place if the investment could be recovered in this period. This expected decline in the economic value of the asset over a period is true economic depreciation of that asset, which should be recovered in that period.*
>
> - *More generally, given that the DORC value of assets is the value of second-hand assets at any point in time, the decline in the DORC value between two points in time is economic depreciation which should be reflected in current period charges.*
>
> *A number of participants raised the issue of stranded asset risk and suggested an adjustment to the Rate of Return is necessary to take this into account. While it was stated in section 4.5 that the regulator will not impose stranding of common-use assets in the near future, it is noted that the regulator cannot guarantee that the asset owner will be able to recover its investment over its regulatory life, for example, in the face of major technological change which introduces a cheaper substitute for gas. It is also noted that by-pass of the system is permitted, which could lead to stranding of assets.*
>
> *To the extent that there is some risk of stranding for some assets before the end of their proposed regulatory life, conceptually there are two options for recognising this in the regulatory framework: to increase the rate of return on capital, or to increase the rate of return of capital. However, following from the discussion above, the Office considers that the perception of stranded asset risk reflects a concern that capital is not being depreciated sufficiently fast to keep pace with its DORC valuation. This would imply that regulatory*

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8 Office of the Regulator-General Victoria (1998), Access Arrangements for Multinet, Westar and Stratus – Final Decision, October, p.95. The assumption in the ORG's discussion is that the DORC valuation for a gas distribution service would reflect the cost of providing the same service (i.e., delivery of energy to consumers) using different technology (i.e., an electricity network) and so capture the economic stranding of gas distribution assets. This broader concept of optimisation is part of a DORC valuation if applied consistently with its theoretical roots.

> *depreciation is lagging true economic depreciation, so that the most appropriate response is to realign the two by increasing the rate of regulatory depreciation.*

Notably, this statement of the regulator was made in a regulatory decision that predated the privatisation of the Victorian gas distribution businesses. The ORG further expanded on its views about the importance of flexibility in depreciation – and using this to provide confidence that costs will be recovered – when undertaking its next review (in that case, the price controls for electricity distributors) which was around the time of the privatisation of the Victorian gas businesses, as follows:[9]

> *The regulatory asset base represents the regulator's view of the market value of the regulated business at any point in time. Accordingly, the regulator can be interpreted as making an implicit commitment to ensure that the market value of those assets does not fall below the regulatory asset base over time. The objectives of encouraging efficient investment will only be met if this remains a credible commitment.*
>
> *This has important implications for the design of the regulatory depreciation profile. In particular, in order to ensure that the regulatory asset base remains at or below the market value of the assets, the regulatory regime must permit each distribution licensee to have their capital returned at a rate that keeps pace with the decline in the economic value of their assets. This in turn implies that regulatory depreciation must at least keep pace with economic depreciation. This will ensure that the value of the distribution licensee should not be placed in a position in the future where it is not able to set tariffs that are expected to recover the benchmark revenue requirement.*
>
> *...*
>
> *As the assessment of economic depreciation requires a view to be taken on all of these factors, its assessment is a complex and information intensive exercise. Hence, the estimation of economic depreciation will involve a degree of imprecision. The potential complexity of determining economic depreciation, combined with the likely imprecision, suggest that a relatively simple method for calculating regulatory depreciation would be appropriate. However, as information on the factors that influence economic depreciation will be revealed over time, there should also be a preparedness to review the method at future price reviews. In addition, this level of uncertainty, coupled with the advantages of reducing the level of risk faced by the distribution licensees, suggests that the method should err on the side of exceeding, rather than lagging, expected economic depreciation.*

Accordingly, not only do the rules contain the flexibility to maintain the confidence with respect to cost recovery in the face of future market events, this flexibility was emphasised by regulators in the formative years of the gas regime. I observe that the commitment of regulators in those early years that depreciation would be applied in a flexible manner if required to head off potential risks to cost recovery were consistent with the long term interests of consumers at the time, and indeed this was the lens through which the issue was analysed. The commitment to flexibility permitted very long asset lives to be assumed when calculating regulated prices, and also allowed regulators to side-step the question of whether an additional premium should be applied in respect of potential future economic asset stranding, as had been advocated at the time (the position reached was that this risk could be avoided via an appropriate approach to depreciation).

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[9] Office of the Regulator-General Victoria (1999), 2001 Electricity Distribution Price Review – Consultation Paper No.4: Cost of capital financing, May, p.15.

In relation to the remaining depreciation principles, these require that:[10]

- the costs are to be recovered only once, which means that changes to depreciation alter only the timing of cash flows (although advancing cash flow will reduce the exposure to economic asset stranding where this is a risk, and so increase the confidence that costs will be recovered), and

- the costs to be recovered should be spread over time in a manner that optimises the use of the asset – although the rule expresses this in terms of maximising *growth* of gas demand, this has been applied in practice to mean that the allocation of costs across time should minimise the *reduction* in demand.

These principles taken together direct depreciation to ensure (to the extent possible) that costs are to be recovered, but recovered only once, and that this cost recovery should be spread over time in the most efficient manner.

### *Capital redundancy provisions*

The rule change proposal from JEC also referenced the current rule provisions in relation to capital redundancy, which are contained in rule 85. These rules are as follows:

> *1) An access arrangement may include (and the AER may require it to include) a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services (redundant assets) are removed from the capital base.*
>
> *2) A reduction of the capital base in accordance with such a mechanism may only take effect from the commencement of the first access arrangement period to follow the inclusion of the mechanism in the access arrangement or the commencement of a later access arrangement period.*
>
> *3) An applicable access arrangement may include a mechanism for sharing costs associated with a decline in demand for pipeline services between the service provider and users.*
>
> *4) Before requiring or approving a mechanism under this rule, the AER must take into account the uncertainty such a mechanism would cause and the effect the uncertainty would have on the service provider, users and prospective users.*

In my view, these provisions are not directed to the management of *economic* stranding of networks. This is simply because, if a network is subject to *economic* stranding, the removal of assets from the RAB has no effect because regulation is not at that point operating as the constraint on pricing. Rather, the competition from substitutes – most notably electricity – will be the constraint on a network's pricing, and it is this competition that will serve to protect customers.[11]

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10 The final principle suggests that depreciation may be adjusted to address financeability issues (i.e., in the same way that the AEMC has recently enabled for electricity transmission ISP projects), although this is not directly relevant to the topic of the rule changes.

11 An expressed concern driving the rule proposals is that there may be vulnerable customers at particular risk because they are unable to switch to electricity. I do not think this concern is likely to emerge as a real issue in the medium term because gas networks will have an incentive to offer prices that retain as

Rather, the principal original intention behind the asset redundancy provisions was to provide regulators with another lever of incentive regulation, and specifically to provide the incentive for networks to strive to maximise the utilisation of their assets.[12] The original rationale for the capital redundancy provisions described the issue that the original gas code provisions were attempting to address as follows:[13]

> ***Issue***
>
> *The provisions in the Reference Tariff Principles are intended to prevent un-used or under-used capital from being to be recovered through Reference Tariffs, and thereby replicating the outcomes of a competitive market.*
>
> *This is intended to give the Service Provider the strong incentive to increase the throughput of gas through its system, and to offer discounts to increase system utilisation while maximising the contributions from discount Users.*
>
> *On the other hand, the treatment of un-used or under used capital may create a significant source of market risk in relation to a Pipeline, and that the methodology that is adopted for handling un-used or under used capital should have a sound basis.*

However, at the same time, the original framers of the Gas Code recognised that compensation would be required for the additional risk that would be caused by such an incentive scheme. To this end, a capital redundancy scheme can only apply on a forward-looking basis, and the regulator is required to consider the implications of the uncertainty – risk – created by this scheme when making its other decisions.

In practice, however, capital redundancy schemes have not been applied in a material way to pipelines that are regulated under the NGR or, previously, the Gas Code. We think the reasons that capital redundancy schemes have not been used to any material extent is because designing a sustainable capital redundancy scheme raises complex issues,[14] and because the application of price caps to

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many customers for as long as possible, and the benefits of this strategy will flow through to all customers. If there is a final group of customers that is unable to switch (because of a lack of control over appliance decisions or cost) then this would better be addressed by governments.

12 A second potential use of the capital redundancy provisions would be to ensure that where part of the network becomes (physically) stranded, the costs associated with that stranded part of the network would not be recoverable from other customers. This is not a case of economic stranding – it is assumed in the provision that all cost *could* be recovered, just that they *should not*. However, imposing stranding risk in this manner would also create an asymmetric risk and require compensation to preserve NPV=0.

13 Gas Reform Task Force (1996), Information paper to accompany the exposure draft of the National Third Party Access Code for Natural Gas Pipeline Systems, August, p.60. Note that while the discussion of the "issue" in this text suggests that the removal of redundant assets would be automatic (which was consistent with the Exposure Draft of the Code that was released for consultation in August 1996), the final version of the Gas Code stepped back and provided the flexibility to create a capital redundancy scheme, but did not require such a scheme.

14 Estimating the compensation required for the (downside) risk of such a scheme would require the regulator to form a view about the likelihood of a redundancy event and the resulting impact of that event on the RAB, which could not be determined with reference to existing observations. In addition, the change to the RAB that is effected for a given change to demand is also not obvious given the existence of economies of scale (i.e., as a 10 per cent higher demand at the time of construction would

pipelines already provides a strong incentive to promote the efficient use of assets through a much simpler mechanism. We are not aware of any concerns having been raised that gas pipelines are not active in promoting the use of their assets. To this end, one of the earliest discussions given to whether a capital redundancy scheme should be employed was provided by the Victorian regulator, as follows:[15]

> *One argument in favour of regulator-imposed stranding of assets is that this may mimic the outcome of a competitive market. In competitive markets, a fall in use of an asset would cause a fall in the revenue stream, and in turn cause a fall in the value of the asset (which competitive markets value as the net present value of income from that asset). A second argument is that such a regulator-imposed stranding mechanism may provide the distribution businesses with a greater incentive to take actions to reduce the likelihood that assets will become stranded. Such an action may be to offer discounts from the Reference Tariff for Users who can make some contribution to joint and common costs, but cannot (for example due to conditions in its product market) pay the full Reference Tariff.*
>
> *Against this, however, any regulatory mechanism for sharing stranded asset risk will increase the level of risk faced by the Service Provider. In particular, as this would result in an additional downside risk without a compensating upside risk, asymmetry in returns may be introduced. This in turn may provide a justification for additional compensation for the Service Provider to ensure that the expected (or average) value of the revenue stream is maintained. Thus, any system of regulator-imposed stranding will impose real costs on end-users. The inherent difficulties with estimating the actuarially fair value for this compensation also provides a real practical difficulty with any system of regulator-imposed asset stranding. Moreover, any plausible methodology (such as through "re-optimising" the system) is likely not to lead to a significant reduction in the Capital Base anyway, given the large economies of scale and scope that characterise distribution systems.*
>
> *On balance, the Office considers that the value in the Capital Base that is attributable to common-use assets should not be reduced at the next review to reflect the perceived stranding or partial stranding of these assets. …*

Moreover, a capital redundancy scheme would have even less justification today as a tool for encouraging the networks to promote the efficient use of their assets given the real threat of economic stranding that has arisen from outside of the gas regulatory regime. This threat is already providing the networks with a very strong incentive to maximise the value that can be extracted from their networks, which includes maximising the intensity and longevity of the use of their assets.

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ordinarily change construction costs by only a fraction of this, a simple pro-rating of the RAB for the change in demand would be inappropriate).

15 Office of the Regulator-General Victoria (1998), Access Arrangements for Multinet, Westar and Stratus – Final Decision, October, pp.91-92.

*  *  *

If there is any matter that you would like to discuss, please do not hesitate to contact me.

Yours sincerely,

Jeff Balchin
**Managing Director**

Australian Gas Infrastructure Group

# Attachment 2

## Energy Transition

**October 2025**

Dampier Bunbury Pipeline

Multinet Gas Networks

Australian Gas Networks

Australian Gas Infrastructure Group

# Contents

# 1 Executive Summary

Australian Gas Infrastructure Group (AGIG) welcomes the opportunity to provide this submission to the Australian Energy Market Commission (AEMC) in response to its "Gas Networks in Transition" consultation paper. Through our ownership of Australian Gas Networks (AGN), Multinet Gas Networks (MGN) and the Dampier to Bunbury Pipeline (DBP), AGIG operates delivers energy to more than two million customers, operates extensive gas distribution, transmission and storage infrastructure, while actively pursuing renewable gas production, carbon pipeline and carbon capture and storage (CCS) projects across Australia.

We support the AEMC's commitment to ensuring National Gas Rules (NGR) remain fit for purpose and be adaptively applied through the transition to net zero. Through our *Net Zero Ambition*, we are advancing a clear pathway to achieve net zero in our own operations and to enable it for our customers, working collaboratively with governments, industry and research organisations to achieve our Vision of delivering infrastructure essential to a sustainable energy future. We believe our networks play a vital role in this transition, acting as enablers for scaling renewable gas development and supporting a multi-vector energy economy that integrates gas, electricity, and emerging fuels to achieve an affordable, secure and sustainable energy system.

## 1.1. Role of Gas in Australia

In Australia, natural gas accounted for 25% of primary energy consumption in 2023–24[1] and remains critical to the functioning of households, businesses, and industry. Natural gas supports both direct end use in homes and businesses, as well as providing critical firming electricity supply.

Gas use in Australia has shifted over the past 15 years including a shift from predominately baseload electricity generation to a greater focus on supporting reliability, firming, and energy security. This continues a long history of change, from the transition from town gas to natural gas in the 1960s and 1970s, to the current focus on renewable and carbon-neutral gases that support emissions goals while maintaining energy access and system resilience.

AGIG's networks have adapted in the past and are well-positioned to adapt to future developments.

## 1.2. Role of Gas Networks in Australia

AGIG serves around 2.1 million customers through 36,000 kilometres of gas distribution pipelines in Australia. These customers are diverse in geography, scale, and energy needs:

- **Residential customers** make up most connections accessing gas for cooking, hot water, and heating; with preferences and usage patterns shaped by a combination of appliance choices, housing types, energy costs, and comfort expectations – factors that vary significantly across regions and socioeconomic groups.
- **Commercial customers** include a diverse set of more than 35 different user types; businesses such as restaurants, medical services, defence, laundromats, and greenhouses rely on gas to contribute to societal needs. These users often prioritise reliability, cost-effectiveness, and service quality in energy selection, and many operate within regulatory environments that value continuity of service.
- **Industrial customers** account for the largest share of gas consumption comprising more than 30 different user-types who typically depend on gas for high-temperature processes, steam generation, and around-the-clock operations. These include food and beverage manufacturers, the chemicals sector, and materials processing, where electrification is often not technically viable or is cost-prohibitive due to energy density, process integration, or operational requirements.

Given this diversity, there are multiple plausible transition pathways for each individual customer on our network to achieve net zero including biomethane, hydrogen, electrification, synthetic gas and the continued use of natural gas with offsets. Throughout the transition, our infrastructure supports choice, security, and affordability for all customers.

## 1.3. Our Net Zero Ambition

[1] Australian Energy Update 2025, Department of Climate Change, Energy, the Environment and Water, p9.

AGIG is committed to achieving net zero emissions from our operations and supporting our customers to do the same. Our *Net Zero Ambition* is underpinned by three targets with respect to our customers' emissions:

- **Today:** Continue replacing distribution mains, a safety driven program required to minimise leaks on the network, and enabling third-party introduction of renewable gases to our networks. This includes leadership in interconnection policy and new project development.
- **2030:** Targeting renewable and carbon-neutral gas production (by AGIG or third parties) connected to our distribution network, equivalent to 10% the volume) supplied by these networks. AGIG currently has two projects delivering up to a 10% (volume) renewable hydrogen blend to more than 4,000 connections on our distribution networks, with further projects at varying stages of development.
- **2050:** Transition to 100% renewable and carbon-neutral gas. We envision this being delivered through a mix of commercial-scale third-party renewable and carbon neutral gas supply, backed by a mature certification and regulatory framework.

### 1.4. Looking Ahead

Our Australian distribution network is continuing its ongoing evolution to deliver for customers. This evolution is not dissimilar to that seen in electricity where coal and gas once dominated, electricity grids now manage variable inputs from solar, wind, and storage. Likewise, our gas networks are evolving from single-fuel systems to platforms that can deliver multiple renewable gases.

We are preparing for a range of customer and market-driven scenarios to ensure the long-term viability of our networks and services. Through collaboration, innovation, and investment, we are building a net zero gas future that keeps choice, reliability, and affordability at the centre of Australia's energy transition.

# 2 The Role of Gas in Australia

1 Natural gas supplies approximately 25% of Australia's energy needs, supporting residential, commercial and industrial users. Around 66% Australia's natural gas is used directly by homes and businesses, with 34% playing a critical role in maintaining electricity system reliability[2].

2 Australian Government strategies affirm that gas will be needed through to 2050 and beyond under all credible net zero scenarios. Gas infrastructure will remain essential as gas use evolves – providing reliability, firming and energy security throughout the transition.

3 Many Australian jurisdictions maintain a technology-neutral energy policy framework that prioritises reliability and affordability while supporting the development of renewable gases and the broader green industrial transition. The National Hydrogen Strategy (2024)[3] demonstrates the Australian Government's commitment to advancing renewable hydrogen and related renewable gases as part of the nation's future energy mix.

## 2.1. Role of Gas in Today

At Financial Year (FY) 2024, natural gas supplied a quarter (25%) of the Australia's energy needs alongside coal (41%), renewables (9%), and liquid fuels (oil/Liquid Petroleum Gas) (25%) (refer Figure 1).

*Figure 1: Percentage of primary energy consumption in Australia by fuel type (2023-24)[4]*

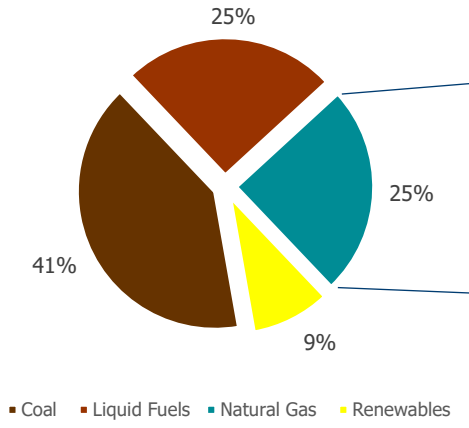
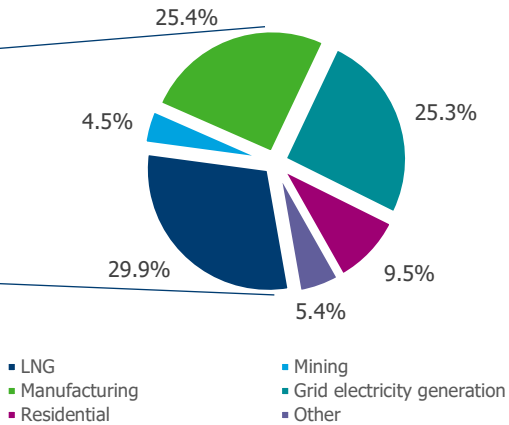



*Figure 2: Percentage of domestic gas use by type (2023-24)[5].*




AGIG supplies a significant portion of direct gas used in Australia to around 2.1 million connections through our networks. Patterns of use are relatively predictable year-round, with some seasonal fluctuations driven by weather.

[2] Australian Energy Update 2025, Department of Climate Change, Energy, the Environment and Water, p9.

[3] National Hydrogen Strategy 2024, Department of Climate Change, Energy, the Environment and Water, p1.

[4] Australian Energy Update 2025, Department of Climate Change, Energy, the Environment and Water, p9.

[5] Ibid.

## 2.2. Role of Gas in the Future

Discussion around the future role of gas has seemingly taken on a higher profile in recent years, but in practice, Australia's oil and gas industry has adapted and evolved in line with customers' needs for generations. This includes the transition from manufactured 'town gas' to cleaner, more reliable natural gas from the 1960s.

The storability, reliability, and flexibility of gas means that it is viewed as increasingly critical in the transition to a system increasingly featuring variable renewable electricity. The Australian Government's Future Gas Strategy establishes that *"under all credible net zero scenarios, natural gas is needed through to 2050 and beyond, though its production and use will change over this period".*

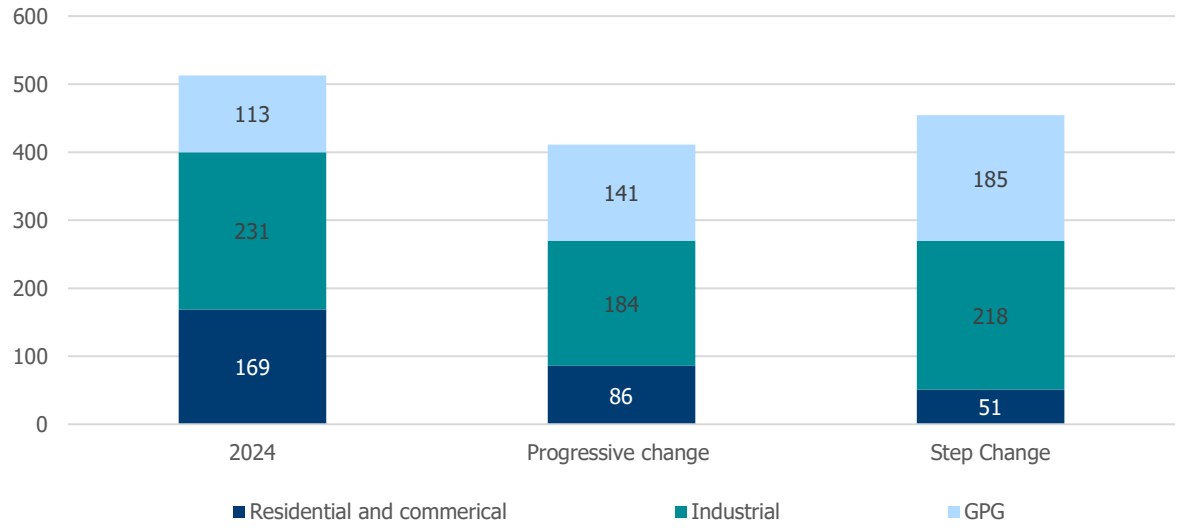
The Future Gas Strategy is underpinned by six guiding principles, which include maintaining affordability, ensuring fit-for-purpose energy systems, and supporting a shift in supply toward higher value and non-substitutable uses. Importantly, it reaffirms as part of Principle 4 that *"households will continue to have a choice over how they meet their energy needs".*

Together with the Australian Energy Market Operator's (AEMO's) 2025 Gas Statement of Opportunities (GSOO), which affirms an enduring role for natural gas across net zero scenarios, these national outlooks affirm that gas will remain a key – though increasingly adaptive – part of Australia's future energy system.

### 2.2.1. Natural Gas Demand

AEMO's annual GSOO provides long-term demand outlooks for the east-coast gas market and the Northern Territory under different scenarios, reflecting different assumptions about renewable gas and electrification as influenced by technology adoption, economic growth and policy settings (refer Figure 3).

*Figure 3: Australia's Forecast Annual Natural Gas Consumption (PJ), 2044[6]*




The 2025 GSOO forecasts that total gas use is expected to be between 80 and 88% of 2024 levels to 2044, reaching around 411PJ under the Progressive Change scenario and 454PJ under the Step Change scenario.

When Gas Powered Generation (GPG, primarily serviced by transmission pipelines) is excluded, residential, commercial and industrial consumption reduces by approximately two-thirds from ~400PJ to ~270PJ in 2044. This highlights the enduring role of gas distribution infrastructure in meeting customer energy needs, even under AEMO's most aggressive Step Change scenario.

[6] AEMO Gas Forecasting Data Portal, accessed October 2025. Data includes Australian residential, commercial, industrial, and GPG gas demand forecasts under various 2025 GSOO scenarios. Not included are figures for LNG, Electrification, Energy Efficiency and Price Impact.

### 2.2.2. Natural Gas Supply

Proved-and-probable natural gas reserves are sufficient to meet around 70 years of Australian consumption at existing levels of demand[7]. Concerns over gas shortages have emerged in recent years, not because Australia lacks gas but because investment has been impacted by a range of factors including successive policy and price interventions.

AEMO's 2025 GSOO highlights potential gas supply shortfalls in eastern and southern Australia from 2028 due to declining production and increased GPG demand. It is important to place these projections in context noting AEMO has signaled potential gas shortages each year since the 2017 GSOO, and electricity shortages have commonly been forecast for more than two decades in the equivalent Electricity Statement of Opportunities.

The 2025 GSOO shows a materially stronger near-term outlook than previous years. This is reflective of an industry response to streamlined approvals for critical energy projects with key infrastructure capacity additions such as APA's East-Coast Grid Expansion, the Moomba–Sydney compression upgrade and Lochard Energy's extra 0.4PJ of Iona storage.

Where renewable gas is unavailable or limited, natural gas could play a role provided its emissions are offset to support net zero. The continued use of small volumes of natural gas helps maintain optionality and reduces transition costs by enabling a more gradual, flexible shift.

### 2.2.3. Renewable Gas Supply

Australia's potential renewable gas supply is now well recognised across multiple government and industry reports. Table 1 summarises recent Government-led or commissioned reports that estimate the scale of opportunities nationally.

*Table 1: Noteworthy Government Renewable Gas Supply Estimates*

| Source | Purpose | Estimated Supply |
|---|---|---|
| **Gas, liquid fuel, coal and renewable gas projections** (ACIL Allen for AEMO, 2025) | Hydrogen and biomethane forecast | Between 40-220PJ of hydrogen and 250-270PJ of biomethane could be available by 2030, increasing to 200-3,200PJ and 480-500PJ by 2050. |
| **Australian Government National Hydrogen Strategy** (DCCEEW, 2024) | Hydrogen target | At least 15 million tonnes of hydrogen per year by 2050 (2,130PJ), with 0.5 million tonnes by 2030 (71PJ). |
| **2024 Integrated System Plan** (AEMO, 2024) | Hydrogen forecast | Hydrogen could make up 27% of Australia's energy use by 2050 under a 'Hydrogen Superpower' scenario. |
| **2023 Gas Statement of Opportunities** (AEMO, 2023) | Biomethane forecast | ~75PJ of biomethane could be produced nationally by 2030 (Figure 31). |
| **Australia's Bioenergy Roadmap** (Australian Renewable Energy Agency, 2021) | Biomethane forecast | 39PJ could be available to 'pipeline gas' by 2030 under a 'business as usual' scenario, 50 and 105PJ available under stronger scenarios. Australia's bioenergy resource potential to be over 2,600PJ per year. |

AGIG has further conducted dedicated studies to understand the potential for renewable gas in its key markets:

- **Biomethane Potential in AGIG's Network Catchment and Associated Co-benefits** (July 2024) provides a granular assessment of how Australia's biomethane potential could translate to supply into AGIG's networks. Blunomy identified 84.6PJ of recoverable biomethane in across South Australia, Queensland and Victoria. These estimates could grow to 323.5PJ under supportive policy settings.
- **Australian Hydrogen Centre** (AHC) (August 2023) explored the technical and economic feasibility of 10% and 100% hydrogen supply to South Australian and Victorian gas networks. The AHC's work demonstrated that it is technically and economically feasible to continue to use existing infrastructure to achieve a 100% renewable hydrogen distribution system,

[7] Geoscience Australia (2024). Australia's Energy Commodity Resources: Gas. Retrieved from https://www.ga.gov.au/aecr2024/gas estimates 2P gas reserves at 108,920PJ compared with an existing annual natural gas usage of 1,500PJ.

including projected hydrogen production capacity of up to 90MW to supply 10% hydrogen by volume in the State, and 2,400MW to supply 100%. The AHC's work program provides clear guidance to third-party hydrogen suppliers on the potential for offtake through AGIG's networks in South Australia and Victoria, and how it might be achieved.

Together, the reports suggest that renewable hydrogen and biomethane could supply a material and growing share of Australia's future energy needs while utilising existing gas infrastructure.

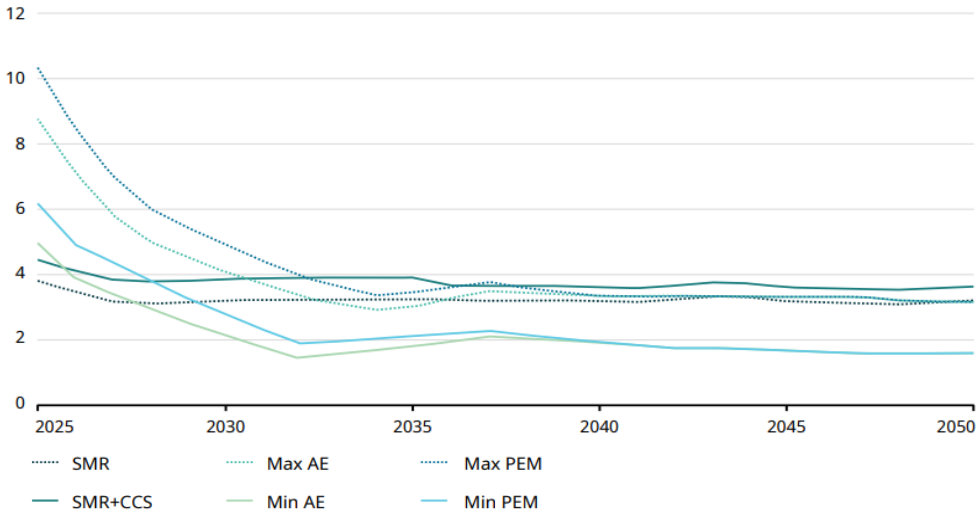
### 2.2.4. Renewable Gas Costs

As an emerging industry both globally and in Australia, hydrogen and biomethane are currently higher cost to produces compared to well established natural gas extraction. However, advances in technology and other enablers indicate it is possible to rapidly bring down production costs as projects are supported to realise scale deployment.

#### Hydrogen Costs

Analysis presented in the 2024 National Hydrogen Strategy indicates Australian hydrogen production costs will fall substantially over the coming decades. Current renewable hydrogen costs are approximately $5–10/kg ($36–72/GJ), with projections of ~$1.5–4/kg ($12.50–33/GJ) by the mid-2030's driven by expected reductions of 40–60% in renewable electricity costs and 88–94% in electrolyser costs (refer Figure 4) [8].

*Figure 4: Levelised Cost of hydrogen production by method over time ($/kg)*




The National Hydrogen Strategy notes other analyses suggest globally competitive production costs are likely to be in the range of US$1-2/kg in 2050[9].

This projection, combined with the legislated $2/kg Hydrogen Production Tax Incentive for certified low-emissions hydrogen from 2027, strengthens the case for hydrogen to become cost-competitive with natural gas over the medium-to-long term.

#### Biomethane Costs

Biomethane costs vary widely by project, influenced by factors such as plant size, feedstock quality and location, local landfill levies, digestate market value, and commercial terms for sourcing residues.

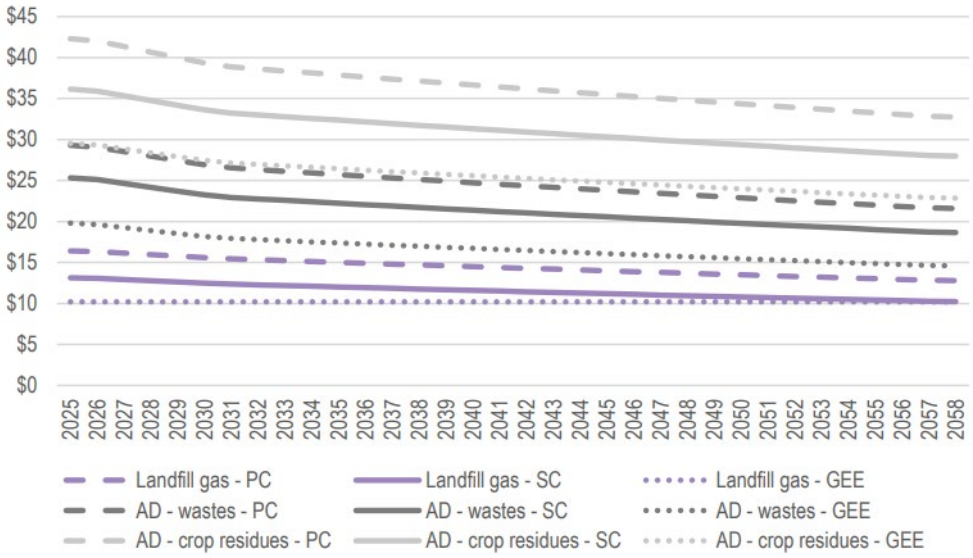
As part of its recent 'Gas, Liquid Fuel, Coal and Renewable Gas Projections: Final Report for AEMO', ACIL Allen estimated high-level cost curves for key biomethane sources – landfill gas, waste, and crop residues – under each AEMO scenario. Current biomethane costs range from approximately $13–35/GJ depending on the source, with projections falling to $10–27/GJ by 2058 (refer Figure 5)[10].

[8] DCCEEW. 2024. *National Hydrogen Strategy*, Figure 5, page 15.

[9] For example, McKinsey and Hydrogen Council 2023, Global Hydrogen Flows – 2023 Update.

[10] ACIL Allen. *Gas, Liquid Fuel, Coal and Renewable Gas Projections: Final Report for AEMO.* Figure B.1, p. B-8.

*Figure 5: Biomethane cost by feedstock, scenario and year ($/GJ)*




Note: PC = Progressive Change scenario; SC = Step Change scenario; GEE = Green Energy Exports scenario.

This suggests some biomethane projects may already be competitive with natural gas today – as evidenced by Delorean's SA1 project commencing construction which will supply biomethane in to the AGIG South Australian gas distribution network – with further uplift possible under favourable policy settings.

## 2.3. Australia's Energy and Climate Policy Context

### 2.3.1. Climate Goals and Electricity Target

At the national level, Australia has legislated a target to reduce greenhouse gas emissions by 43% below 2005 levels by 2030, increasing to 62% to 70% by 2035 and achieving net zero emissions by 2050. The federal government also expects that renewable electricity will make up a large share of generation. The "Powering Australia" agenda assumes that 82% of electricity will be sourced from renewables by 2030.

### 2.3.2. Natural Gas Policy

The Australian Government recognises natural gas as essential to the energy transition, particularly to firm renewables, support reliability, and maintain affordability[11]. This position is reflected in recent initiatives such as the 2024 Future Gas Strategy where government noted *"under all credible net zero scenarios, natural gas is needed through to 2050 and beyond, though its production and use will change over this period".*

Looking ahead, Australia supports the progressive decarbonisation of natural gas and its infrastructure through hydrogen, biomethane, and Carbon Capture and Storage (CCS). At the national level, Energy Ministers have agreed to expand the national gas regulatory framework to include hydrogen, biomethane and other renewable gases, thereby providing regulatory certainty for investment in low-carbon gas pathways[12].

### 2.3.3. Hydrogen Policy

Australia has supported hydrogen industry development through several policy frameworks, most recently embodied in the 2024 National Hydrogen Strategy, evolving from the 2019 strategy. The refreshed strategy places stronger emphasis on scaling clean hydrogen production, incorporating production incentives such as the $6.7 billion Hydrogen Production Tax Incentive and expanded $2 billion Hydrogen Headstart funding to help bridge the cost gap for renewable hydrogen.

[11] Australian Government. 2024. Future Gas Strategy, p. 5, accessed 16 October 2025.

[12] Energy.gov.au. 2024. Extending the National Gas Regulatory Framework to Hydrogen and Renewable Gases, accessed 16 October 2025.

While some individual projects have encountered delays or adjustments in scope, as with many segments of the energy sector, government remains committed to hydrogen's long-term role in decarbonisation. The National Hydrogen Strategy provides continuity and direction, while state initiatives such as licensing reforms and infrastructure hubs provide the enabling environment for deployment.

### 2.3.4. State and Territory Policies

Across the states and territories where AGIG operates (New South Wales, Northern Territory, Queensland, South Australia, Victoria and Western Australia), natural and renewable gas have recognised roles in the energy transition for distribution networks.

Renewable gas development and use has been supported by funding and regulatory reforms across all states. Notably, reform to the National Gas Law (NGL) and National Gas Rules (NGR) to enable 'covered gases' has enabled several renewable gas projects linked to distribution networks to proceed. Furthermore, direct funding has been provided by several states to support AGIG-led renewable gas projects involving our distribution networks.

In addition, in 2024, GreenPower introduced a pilot for Renewable Gas Guarantee of Origin (RGGO) certificates, allowing commercial and industrial gas users to match their gas consumption with certified renewable gas (see Section 3.2.3 for more information). The pilot is now a recognised national certification scheme providing independent verification of the attributes of renewable gas production including biogas, biomethane, e-methane and renewable hydrogen.

State and territory policies and laws across all jurisdictions where AGIG operates continue to permit the use of natural gas, and none have announced plans to decommission any part of an AGIG network. With the exception of Victoria, no other state or territory in which we operate restrict or prohibits new gas connections, and several have confirmed they do not intend to prevent residential customers from accessing natural gas.

*Table 2: State and Territory gas distribution network policies where AGIG operates*

| Gas Distribution Network Policy | New South Wales | Northern Territory | Queensland | South Australia | Victoria | Western Australia |
|---|---|---|---|---|---|---|
| **Gas network access** | Open to new connections | Open to new connections | Open to new connections | Open to new connections | New residential and some commercial buildings restricted from 1 Jan 2027 | Open to new connections |
| **Electrification requirements** | Customer choice maintained | Customer choice maintained | Customer choice maintained | Customer choice maintained | Restrictions to residential gas hot water systems from 1 Jan 2027 | Customer choice maintained |
| **Gas network decommissioning** | None proposed | None proposed | None proposed | None proposed | None proposed | None proposed |
| **Renewable and carbon-neutral gas use** | Actively explored, including through supportive policy such as the Renewable Fuels Scheme | Actively being explored | Actively being explored | Actively being explored | Actively being explored, including through proposed renewable gas targets | Actively being explored |

It is noteworthy that recent Victorian Government policy decisions on new gas connections and appliance changeovers represented a softening of earlier proposals, recognising the customer choice, economic, technical, and practical factors that support ongoing access to gas network infrastructure.

While some of the 2.2 million customers currently connected to Victorian natural gas networks may choose to electrify over time, many are expected to continue using gas given its reliability, affordability and suitability for a wide range of applications. AGIG's networks will continue to provide reliable service for these customers and are well positioned to deliver renewable and carbon-neutral gases as the transition progresses[13].

[13] Media Release - Policy shift but gas hot water ban still leaves households behind | AGIG

# 3 The Role of AGIG's Gas Networks

1. Our Australian gas network is extensive and strategically significant, comprising over 36,000 kilometers of gas distribution pipelines and over 4,300 km of transmission assets delivering gas to ~2.1 million customers.
2. Connection growth has remained stable through continued interest from residential customers, growing between 0.8-1.1% each year (refer Figure 6).
3. Network access is dominated by residential connections (97%), however consumption is equally split between residential customers and Commercial and Industrial customers (~66PJ each respectively), reflecting diverse needs and use profiles, as evidenced by the split in consumption by state as:
    a. Queensland (14% residential / 86% Commercial and Industrial), New South Wales (38% residential / 62% Commercial and Industrial), and South Australia (26% residential / 74% Commercial and Industrial) are C&I-led.
    b. Victoria (59% residential / 41% Commercial and Industrial) is residential-led.
4. Customers rely on gas for a range of reasons – such as process heat, energy reliability, cost-effectiveness or appliance preference – and are best placed to decide how and when to transition, based on their individual circumstances.
5. The network spans metropolitan, regional, and industrial areas, enabling tailored carbon reduction approaches and enhancing resilience across energy, water, and waste sectors.
6. The network is well positioned to deliver renewable and carbon-neutral gas, and to support a more integrated and flexible energy system through sector coupling and storage.

### 3.1. AGIG's Distribution Network

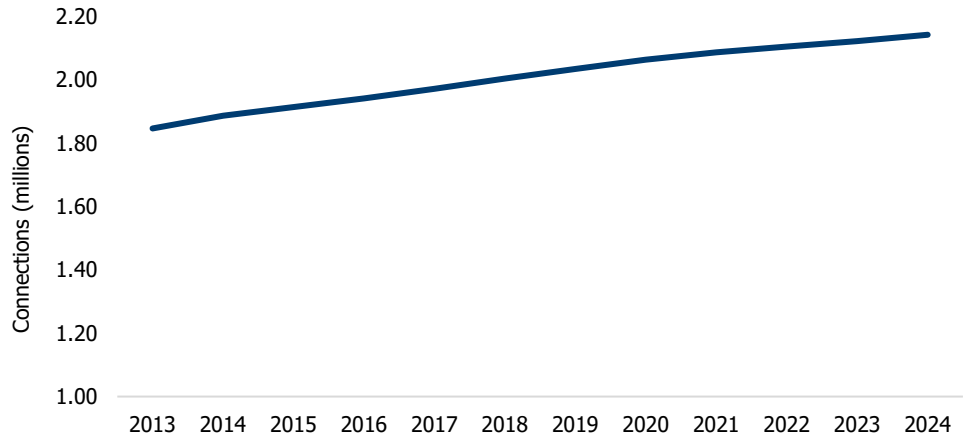
The history of AGIG's gas distribution networks dates back more than 160 years, with networks established in Melbourne, Adelaide and Brisbane from the 1850s to supply manufactured 'town gas' to households and industry. The development of these networks played a critical role in supporting Australia's economic growth and industrial development, enabling communities and businesses across the nation to access a reliable energy source.

The network is underground, reducing exposure to severe weather impacts and supporting secure energy supply. It enables the storage, transport, and use of both natural and renewable gases, connecting buyers and sellers across a broader market.

#### 3.1.1. Connections and Use

As outlined in Figure 6, connection growth has remained stable driven by continued interest from residential customers, growing between 0.8-1.1% each year.

*Figure 6: AGIG Connection Growth 2013-2024[14]*




Usage varies significantly between customer groups. Residential customers make up over 97% of connections but accounted for around 50% of total gas use in 2024 (refer Figure 7). By comparison, commercial and industrial users accounted for around 3% of connections but used similarly 50% of total demand (refer Figure 8).

*Figure 7: AGIG Connections By Customer Type (2024)*

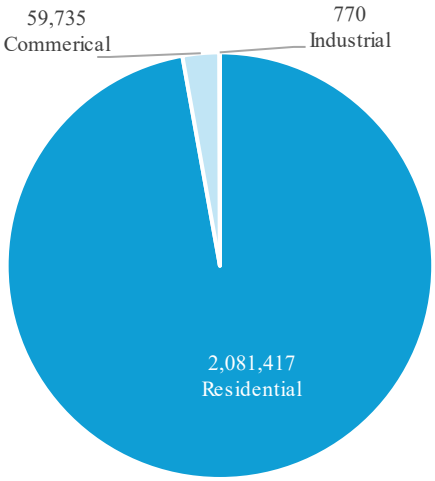
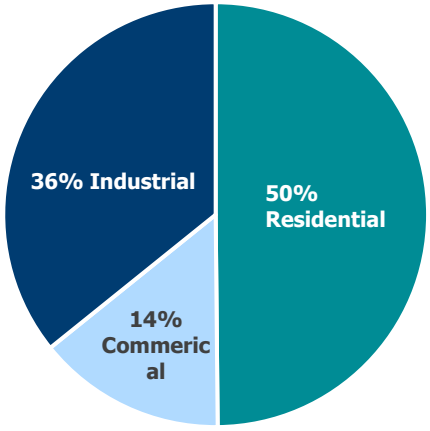



*Figure 8: AGIG Total Gas Use By Customer Type (% of Total Consumption) (2024)*




### 3.1.2. AGIG Network Mapping

The following sections provide an overview of different users on AGIG's Australian networks and chart their geographic footprint. The network mapping illustrates the interconnected nature and the diversity of our assets; with the composition of residential to commercial and industrials (C&I) customers varying from one jurisdiction to another; as well as the usage within each sector varying between archetype.

[14] AGIG Annual Reports 2014 - 2025

**Interconnected Networks**

Figures 9 through 11 illustrate the interconnected nature of networks, with residential customers collocated with commercial and industrial users

*Figure 9: Greater Melbourne*

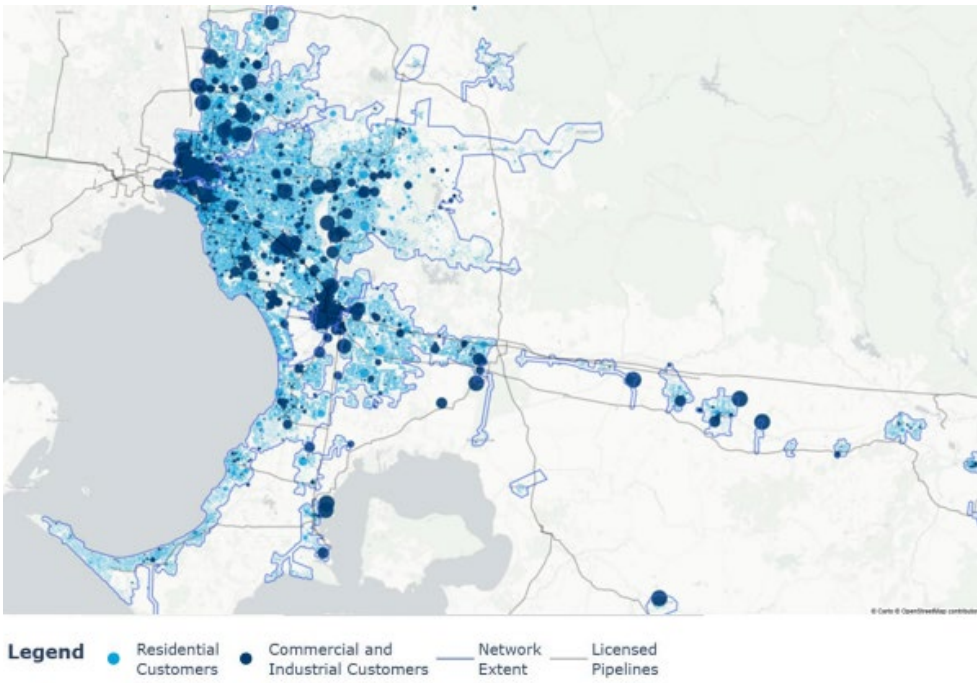



*Figure 10: Greater Adelaide*

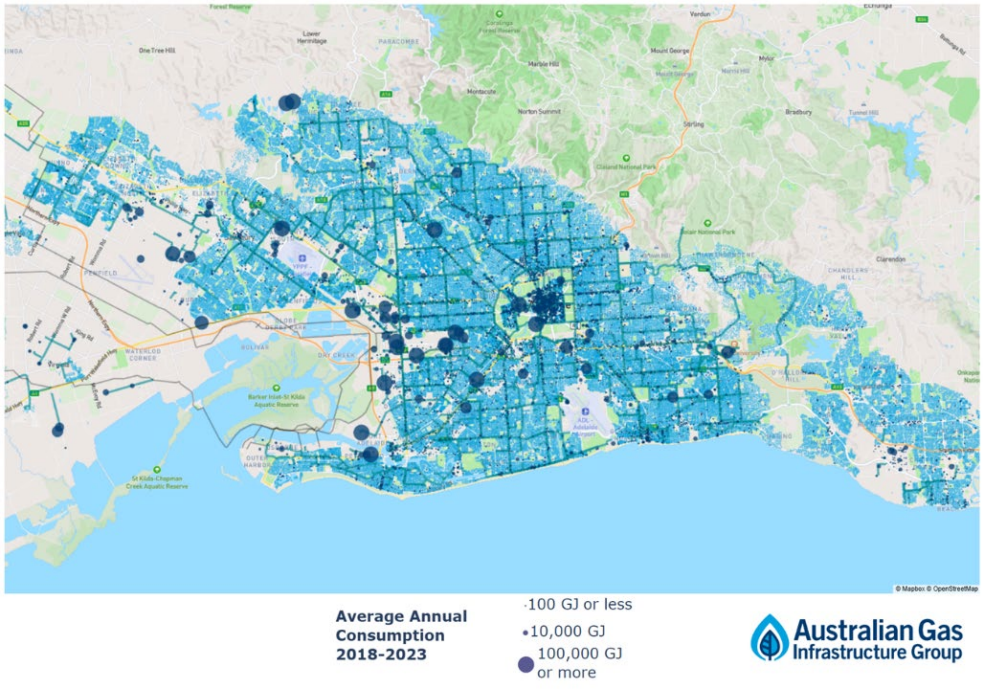
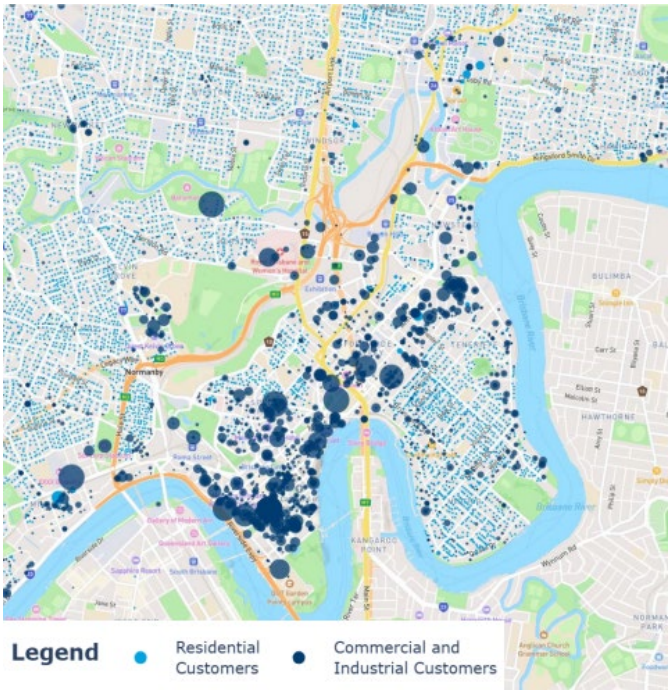


*Figure 11: Greater Brisbane*




**Residential Customers**

Residential customers on AGIG's distribution networks vary by state in dwelling type, number of appliances, energy use, consumption level and financial wellbeing. Most live in detached dwellings and use gas for cooking and hot water, with Victorian customers also typically using gas for space heating.

Average residential consumption differs markedly by state. In Victoria, customers consume around 49GJ per year, representing 54% of residential connections. In South Australia, average consumption is 13 GJ per year and accounts for 39% of connections, while in Queensland, customers use around 9GJ per year, representing 60% of residential connections.

While consumption per connection has declined over time, overall residential connections remain stable or growing in all jurisdictions, including ~5% growth in Queensland from 2020–2024. These trends demonstrate continued customer value in maintaining gas access, even as usage patterns evolve and demand profiles change.

**Commercial and Industrial Customers**

Commercial and industrial gas use is spread across various locations without any discernible geographic pattern, indicating that its utilisation is not concentrated in specific regions or communities.

Table 3 outlines the significant mix of different end-use cases, with no single archetype contributing more than 18% of total commercial and industrial gas use. These sectors are significant contributors to the Australian economy and also service important community infrastructure such as cafes, bakeries, medical services, swimming pools, primary schools and car repair. As outlined in the Deloitte Report for Bioenergy Australia, many of these sectors will continue to rely on gas into the future[15]:

> *"Gas powers Australia's $100 billion manufacturing industries. Gas is a critical energy source and raw material for manufacturing and many industries depend on gas to produce aluminium, chemicals, cement, bricks, and plastic packaging for foods and beverages.*
>
> *Many gas applications have few decarbonisation options available, and gas will remain a critical energy source for these applications into the future".*

[15] Deloitte, Unlocking Renewable Natural Gas to Enhance Energy Security and Maintain Australia's Manufacturing Sector, 2025, 0utdqum1meyoizrw.pdf.

*Table 3: Commercial and Industrial Customer Type and Consumption connected to AGIG gas distribution networks*[16]

| Archetype | Commercial and Industrial Gas Consumption (%) | Average Annual Gas Consumption (PJ) |
|---|---|---|
| Buildings | 17.7% | 12.0 |
| High Temperature Metal Product Manufacturing | 12.0% | 8.2 |
| Food Product Manufacturing | 8.9% | 6.0 |
| Cement, Concrete, Lime and Plaster Manufacturing | 8.7% | 5.9 |
| Pulp, Paper and Printing | 5.9% | 4.0 |
| **>50% Of Annual C&I Consumption Above This Line** | | |
| Dairy | 5.2% | 3.5 |
| Hospital | 5.0% | 3.4 |
| Glass | 4.8% | 3.3 |
| Cafes, Restaurants, Fast Food and Takeaway | 4.2% | 2.8 |
| Unknown | 4.0% | 2.7 |
| **>75% Of Annual C&I Consumption Above This Line** | | |
| Medical Services | 3.0% | 2.0 |
| Direct Gas Use | 2.7% | 1.8 |
| Breweries, Distilleries and Wineries | 2.4% | 1.7 |
| Abattoirs and Meat Processing Facilities | 2.4% | 1.6 |
| Asphalt | 1.4% | 0.9 |
| Chemical Manufacturing | 1.3% | 0.9 |
| Laundry | 1.3% | 0.9 |
| Bricks | 1.1% | 0.8 |
| Greenhouse | 1.1% | 0.7 |
| Polymer Product Manufacturing | 1.0% | 0.7 |
| Bakery | 0.9% | 0.6 |
| Automotive Manufacturing and Repairs | 0.8% | 0.5 |
| **>95% Of Annual C&I Consumption Above This Line** | | |
| Wood Manufacturing | 0.7% | 0.5 |
| Equipment Manufacturing | 0.6% | 0.4 |
| Textile Manufacturing | 0.5% | 0.3 |
| Lower Temperature Metal Product Manufacturing | 0.4% | 0.3 |
| Defence | 0.4% | 0.2 |
| Power Stations and Co-Gen Facilities | 0.4% | 0.2 |
| Pharmaceutical Manufacturing | 0.3% | 0.2 |
| Waste Treatment Facility | 0.2% | 0.2 |
| Agriculture | 0.2% | 0.2 |
| Creative and Performing Arts Activities | 0.2% | 0.1 |

[16] AGIG internal analysis of commercial and industrial customer data on AGIG's distribution networks, developed with GPA Engineering.

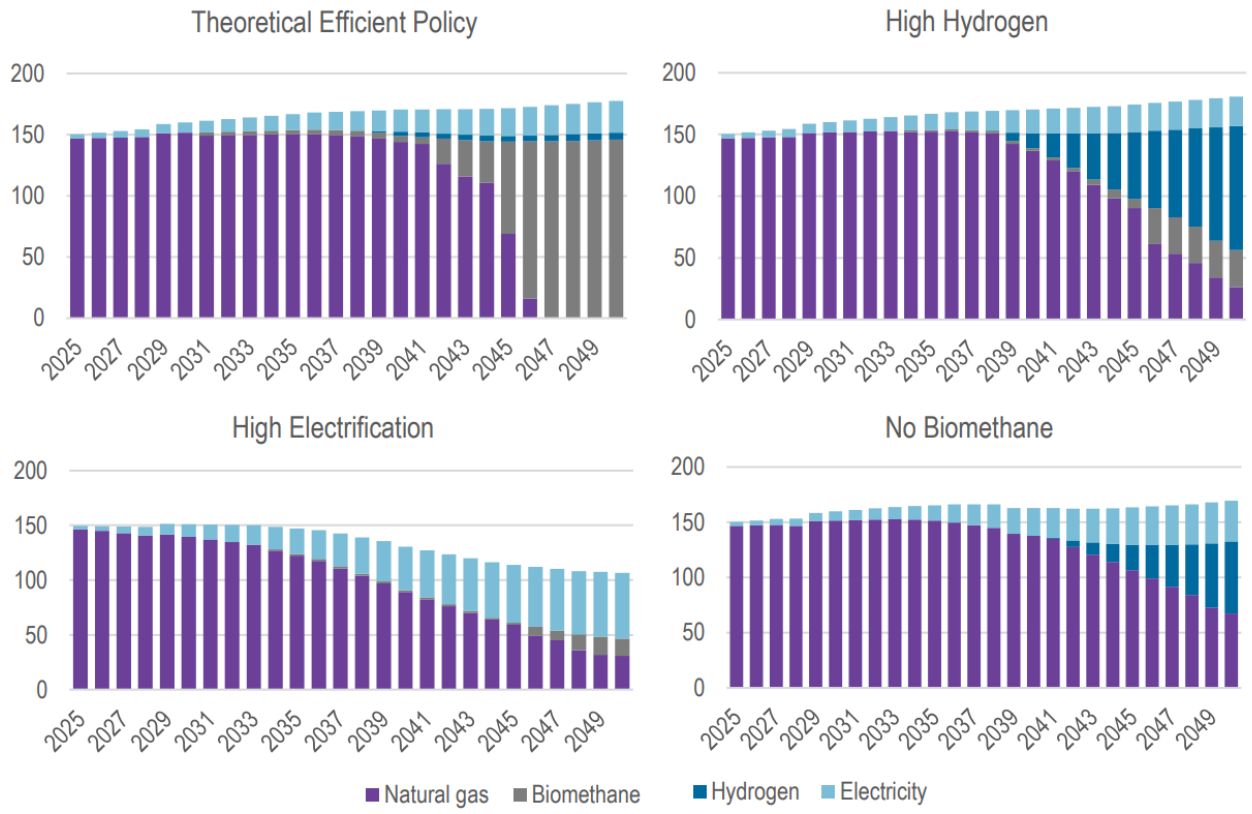
| Archetype | Commercial and Industrial Gas Consumption (%) | Average Annual Gas Consumption (PJ) |
|---|---|---|
| Paint and Coatings Manufacturing | 0.2% | 0.1 |
| Coffee Roasters | 0.1% | 0.1 |
| Waste Water Treatment Plant | 0.1% | 0.1 |
| Rubber Manufacturing | 0.1% | 0.1 |
| Crematorium | 0.1% | 0.04 |
| Char Manufacturing | 0.03% | 0.02 |
| Adhesive Manufacturing | 0.02% | 0.02 |

### 3.2. Prospective Gas Supply Futures

Section 3.1 demonstrates the diverse range of customer requirements on AGIG's network. Each household and business faces a unique and evolving set of considerations when deciding how to meet their energy needs in line with net zero goals – such as cost, infrastructure compatibility, operational requirements, and cultural or lifestyle preferences.

This diversity supports multiple transition pathways, including biomethane, hydrogen, electrification, and offset natural gas. In 2024, ACIL Allen modelled the lowest-cost path to net zero, showing that shifts in technology and costs could alter the optimal fuel mix[17].

*Figure 13: ACIL Allen: Residential fuel mix (PJ): Theoretical Efficient Policy scenario and selected sensitivities*




[17] ACIL Allen. 2024. *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy,* prepared for APGA and ENA, Figure 3.15, p. 27.

When managing the transition for millions of Australian customers, we anticipate an approach where new supply projects, whether biomethane, hydrogen, or others such as synthetic methane, emerge in line with resource availability, infrastructure readiness, and end-user demand. For example:

- **Biomethane-led scenarios:** With some projects commercially competitive today ($13-35/GJ) and no need for appliance modification, biomethane can be integrated quickly and seamlessly when supply is available [18]. Biomethane-rich regions such as parts of northern Adelaide and the Murraylands (South Australia), the Darling Downs and Toowoomba regions (Queensland), the Goulburn Valley and Gippsland (Victoria), New England and Riverina regions (New South Wales) may align more naturally with this pathway due to the presence of large biogas producers and agricultural activity.
- **Hydrogen-led scenarios:** Hydrogen adoption may occur more gradually, given higher relative fuel costs ($36–72/GJ) and the potential need for appliance modification beyond 20% blending[19]. However, hydrogen production costs are expected to decline significantly by the mid-2030s. Adelaide could be well served by the proposed Hydrogen Park Adelaide and potential future expansions. Should the Port Bonython Hydrogen Hub progress or Hydrogen Jobs Plan resume, networks in Whyalla and Port Pirie would be well positioned for a hydrogen-led pathway, given their proximity to commercial-scale hydrogen production and high industrial demand.
- **Natural gas as a backstop:** Where hydrogen or biomethane are unavailable or limited, natural gas could play a role provided emissions from this natural gas is offset to achieve net zero. Continuing to use small volumes of natural gas can help maintain optionality and reduce transition costs by allowing for the gradual replacement of household appliances.

The gas network is entering a phase of transformation, moving from a single-fuel model to a multi-vector energy platform. We are actively planning for these future configurations. While the exact supply mix remains uncertain, the role of our network remains clear. By maintaining optionality, enabling new gas sources, and supporting customer choice, we will continue to provide a reliable energy service that adapts to local and national needs through the transition to net zero.

[18] Refer 1.2.4. for discussion on hydrogen and biomethane supply cost projections

[19] Ibid