



# Jemena Limited

## Gas networks in transition

Response to consultation paper



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## Executive summary

Jemena welcomes the opportunity to submit into the Australian Energy Market Commission's (**AEMC's**) gas networks in transition rule change process. Through the Jemena Gas Network (NSW) Ltd (**JGN**), we deliver gas to over 1.5 million residential, business and industrial customers in Sydney, Newcastle, the Central Coast, Wollongong and more than 20 regional centres. Residential customers make up 97.7 percent of our customers who consume 31 percent of gas hauled across our network. By contrast, our largest 400 industrial customers (including gas powered generation) use 54 percent of gas hauled on our network, emphasising JGN's importance to support New South Wales (**NSW**) industry. Small businesses and commercial make up the remaining 2.3 percent of customers, consuming 15 percent of gas hauled. Jemena also own a number of gas transmission pipelines serving customers throughout Queensland, NSW, Victoria and the Northern Territory.

Australian energy consumers have benefited from a long period of a stable and predictable regulatory framework. This stability and predictability has served to bring significant investment into long-lived infrastructure assets, while supporting lower costs to customers through those investments being returned over long asset lives and regulated rates of return based on the residual risk the regulatory regime generates for network service providers.

We recognise that gas networks are in transition and that there is a degree of uncertainty on the precise role gas networks will play in the long-term future. Crucially, this transition will vary by jurisdiction with the Energy and Climate Change Ministerial Council (**ECMC**) recognising that each jurisdiction may pursue its own policies on energy transformation according to its unique needs, circumstances and jurisdictional policies.<sup>1</sup> The regulatory framework needs to accommodate for these variances.

In contrast, the narrow narrative provided by the proponents on the future of gas does not take into account all available evidence. Commonwealth government policy envisages a role for gas beyond 2050 and, outside of the ACT, there is no relevant Commonwealth or State government policy that includes plans to decommission gas networks. Even the ACT has yet to develop a practical framework for retiring or repurposing network assets. This does not mean there is certainty, but neither does it mean the proponents' view of the future is the only scenario to plan for.

We have material concerns with the rule changes proposed by Energy Consumer Australia (**ECA**) and Justice and Equity Centre (**JEC**) (together, the **proponents**). Key parts of these proposals serve to unwind the established stability and predictability of the regulatory framework. They would erode regulatory certainty when it is critically needed to support the energy transition.

Further, we do not agree with how the proponents have characterised elements of the regulatory framework. The language of the revenue and pricing principle set out in the National Gas Law (**NGL**) that provides for a reasonable 'opportunity' to recover at least efficient costs is necessary for an ex-ante, incentives based, regulatory framework. NGL does not provide room to remove that opportunity. However, the effect of key elements of the proposals would foreclose on the *reasonable opportunity* to recover efficient costs. It's also emotive and misleading for the proponents to suggest that networks have 'taken advantage' of rules relating to depreciation, when networks have appropriately sought to apply rules within the current framework by seeking to ensure efficient depreciation schedules. Further, suggesting that accelerating depreciation 'transfers costs' to customers misunderstands the regulatory framework that has been put in place to deliver investment to support safe and reliable networks.

The current regulatory framework provides regulators with broad discretion. The proponents' concerns about the current regulatory framework are not substantiated by evidence that demonstrates where regulators have failed to achieve desired outcomes. In fact, evidence supports the regulator having many tools available within the current regulatory framework to manage change. This includes revising down capital and operating expenditure, allowing operating expenditure step changes (such as leak detection), providing changes to the depreciation schedule and requiring adjustments to tariffs and tariff structures. Whether the regulators optimally apply the tools provided to them under the regulatory framework is a separate question as to whether the regulatory framework is fit for purpose.

Further, the AEMC has not provided evidence supporting the statement that the regulatory framework is 'predicated on demand growth'. Moreover, even if accepted as accurate, it does not logically follow that the

<sup>1</sup> ECMC agreed priorities, 15 August 2025: <https://www.energy.gov.au/energy-and-climate-change-ministerial-council>

regulatory framework is therefore unfit for purpose, particularly when specific policy direction within all States remains uncertain. We urge a credible problem statement so that proportionate and well-placed solutions arise.

Beyond seeking to address a problem that has yet to crystallise in government policy, we consider the rule change proposals should not be made for a range of reasons—many of which relate to specific aspects of the proposals.

The issues with the rule change proposals, however, fall broadly into a few key themes:

- **Rule changes fail to meet the National Gas Objective (NGO) when taking into account the revenue and pricing principles<sup>2</sup> on the basis that they take away the reasonable opportunity to recover efficient costs.**

A reasonable opportunity to recover efficient costs is not available under:

- The depreciation and capital redundancy rule changes that require regulated asset base write downs to achieve a change to the depreciation schedule. In this scenario, gas network service providers would need to trade-off between efficient (and often customer-supported<sup>3</sup>) depreciation schedules addressing intergenerational equity concerns and the return of their efficiently invested capital expenditure.
- The proposal to change the capital expenditure criteria to include a requirement for the regulator to assure itself that the service provider has acted prudently in its previous investment decisions before allowing capital expenditure to replace assets. This type of ‘look back test’ creates regulatory uncertainty which is damaging to investor confidence. By denying the opportunity to recover efficient replacement capital expenditure based on the actual current state of the network, it would also provide a perverse investment incentive that risks service degradation and potential safety risks to the detriment of the long-term interests of consumers.
- The proposal to change the capital expenditure criteria to exclude safety improvements from conforming capital. Under this change, management of the network service provider would be investing in safety projects (required to meet Australian Safety Standards<sup>4</sup> and community expectations of continuous safety improvement) that have a negative net present value (NPV). This provides an undesirable incentive that does not support safety. This ultimately hinders a network service providers’ ability to properly manage safety, as well as create uncertainty around liability for safety incidents.
- Changes to the definition of operating expenditure to remove expenditure that supports demand growth, where this co-exists with potential outcomes for gas network service providers to be regulated under a price cap (or hybrid). This would lead to network service providers being required to manage demand risk without a key means to manage that risk. Additionally, it remains in gas customers interests for a networks fixed costs to be spread across as many customers as possible.

At a time when unprecedented investment is required in the energy transition, these types of rule changes would have a profound impact on investment beyond gas network service providers due to the signal that Australia is reconsidering the long-standing stability and predictability of the long-term regulatory framework.

- **Rule changes fail to meet the NGO on the basis of driving inefficient utilisation of the network**—introducing conditions on changing the depreciation schedule may unduly limit regulator flexibility and risks inefficient depreciation schedules. This leads to poor price signals for customers that incentivise them to inefficiently use the network. The AEMC assessment criteria should apply greater focus on efficient utilisation impacts.
- **Rule changes are unworkable**—key parts of the capital expenditure criteria rule change create practical issues:

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<sup>2</sup> Section 293 of the NGL requires the AEMC to take into account the revenue and pricing principles.

<sup>3</sup> JGN, *2025 Plan*, June 2024, p. 35.

<sup>4</sup> The Australian Safety Standards hold gas networks to safety levels of ‘as low as reasonably practical’ and ‘as far as reasonably practical’. See section 3.2 of our submission.

- The 'look back test' for replacement capital expenditure would severely impact regulatory certainty and require numerous new arduous controls and face practical difficulties, not least of which is controlling regulator hindsight bias. These add complexity and cost.
- Removing capital expenditure that 'improves' safety from conforming capital expenditure would create an arbitrary 'point in time' safety level to be maintained, likely conflicting with Australian Safety Standards and community expectations of continuous safety improvement. It would also be difficult to ascertain which capital expenditure of a project 'maintains' a predetermined safety level and that which 'improves' safety.
- The proposed exclusion of renewable-related capital expenditure would impede the regulator's ability to determine reference services within the NGL, where the NGL contemplates that a "pipeline service", and therefore a "reference service" determined by the Australian Energy Regulator (**AER**), may be a service for transportation of renewable fuels. This proposed rule risks undermining the AER's ability to make decisions which are consistent with the NGO.
- Tying capital expenditure to customer value of reliability or seeking demand management solutions appear to be 'taking a leaf' out of the approach to electricity without understanding the fundamental differences between management of a gas and an electricity network. The time, fieldwork required at each meter and costs of restoring gas following an unplanned interruption is completely different from electricity networks. Gas networks costs are not driven by instantaneous peaks as electricity networks are.
- Adjusting the supply of services in NGR rule 79(2) to include the provision of energy services by other means, whether by the service provider or another party would not be consistent with the Ministerial Council decision to retain the NGO and National Electricity Objective (**NEO**) as related to 'consumers of gas' and 'consumers of electricity' respectively (as opposed to 'consumers of energy').

In relation to the planning rule change, we note that since the inception of the regulatory framework, the regulatory burden on network service providers has only increased. As costs are ultimately borne by customers, we urge the AEMC, prior to making any rule that adds to that regulatory burden, to understand:

- What information is already provided and has emerged as part of access arrangement resets
- What information would be sought by State jurisdictions should relevant policy decisions on gas network futures be made (consistent with the ECMC agreed priorities), and then
- What additional information (if any) would provide clear benefits for customers.

## 1. Issues impacting customers and gas distributors

The proponents' and AEMCs' problem statement is not borne out by the evidence. The AEMC response should be proportional to the problem.

This section covers Jemena's response to AEMC

- Question 1: What are the issues impacting consumers and gas distributors under the energy transition?

### 1.1 Limited evidence of need for the rule changes

The issues identified by the proponents, as well as the AEMC problem statement that the current regulatory framework was predicated on demand growth,<sup>5</sup> are not sufficiently supported by credible evidence. The current regulatory framework, established following the 1993 Hilmer report<sup>6</sup> was concerned with efficiently regulating natural monopolies, agnostic to demand movements. While some parts of the National Gas Rules (**NGR**) do reference demand growth,<sup>7</sup> this does not represent an entire regulatory framework. It is not necessary that demand growth is required for these parts of the regulatory framework to operate in the long-term interests of consumers.

Similarly, the proponents provide a narrow view of the future of gas, focusing on residential demand volume decline. While uncertainty of gas demand, and the pipeline network required to support it into the long-term future is heightened, future gas scenarios outside the views presented by the proponents warrant inclusion in any assessment of the rule changes. Importantly:

- Outside the ACT, State and Commonwealth governments have yet to make key policy decisions on the future of existing gas networks. Indeed, the Commonwealth Government 2024 *Future Gas Strategy*, which sets the long-term policy direction for gas in Australia's energy mix, states that "under all credible net zero scenarios, natural gas is needed through to 2050 and beyond". We expand on this in section 1.2.3.
- Only 10 out of 63 NSW local councils (Local Government Area) that JGN services have made decisions to prepare Development Control Plans that do not support new gas connections, with none seeking to phase out existing gas connections. These are guidance to support Local Council policy and they do retain flexibility in how they are applied. Those that do not support new connections are generally limited to new developments (not where existing building permits exist) and do not uniformly include commercial premises. There are also other local councils who have voted down similar proposals that seek to stop new gas connections (eg Willoughby City Council).
- Investment continues in renewable gas infrastructure and technologies (including biomethane and hydrogen), despite significantly less subsidies being provided than in the renewable electricity market—the level of renewable gas entering the pipelines and networks is expected to increase,<sup>8</sup> with the 2024 Gas Statement of Opportunities noting the potential for biomethane blended into transmission and distribution gas pipelines to displace natural gas.<sup>9</sup>
- Gas futures cited by the proponents are those that assume 2050 targets are met—these are helpful for understanding that outcome, but do not necessarily reflect actual consumer preferences or needs. Nor do they reflect:

<sup>5</sup> AEMC Gas Networks in Transition consultation paper, p. i.

<sup>6</sup> National Competition Policy Review, Heads of Australia Governments. Chairman: Prof Frederick C Hilmer. Secretary: Mr Warrick Smith. Members: Mr Mark Rayner. Mr Geoffrey Taperell. 25 August 1993. Heads of Australia Governments.

<sup>7</sup> For example, referenced within the definition of operating expenditure.

<sup>8</sup> Globally, there is a mature market in Europe and North America for biomethane. In Australia, the first biomethane facility has been built at Malabar in NSW. There are also several biomethane investment memorandum of undertakings in place, and another biomethane facility is being built in South Australia (see <https://deloerancorporation.com.au/projects/sa1-salisbury-bioenergy-plant/>)

<sup>9</sup> AEMO, Gas Statement of Opportunities, March 2024, p. 27.

- Potential challenges that may arise in decarbonising the electricity network—while renewable electricity remains scarce, accelerated electrification risks this being a fossil fuelled electrification, creating no net gains for emission reduction or possibly making these worse.<sup>10</sup> Electrification only supports total emissions reductions when providing energy from an electron is less emissions intensive than getting that energy from a gas molecule.
- Given the absence of Commonwealth, State and Territory policy (with the exception of the ACT) to phase out existing gas networks, customers will make future energy use decisions based on the future relative costs of electricity versus gas, which are also uncertain<sup>11</sup>
- Many networks, including JGN's, are still experiencing connections growth (and have regulatory obligations to offer those connections).
- Up to two-thirds of industrial customers on JGN's network are hard to abate. Some are considering converting from coal to gas to abate emissions. New gas-powered stations (with supporting gas infrastructure)<sup>12</sup> are required to support the energy transition. Both will lead to material increase in gas volumes through the network and very significant emissions reduction.

A non-credible problem statement risks a disproportionate and misplaced solution. The regulatory framework already has robust tools to deal with current uncertainty facing gas networks. The future of gas uncertainty has been a feature and trigger for multiple actions taken by gas network service providers in their recent access arrangement proposals.

The Australian Energy Regulator (**AER**) has been able to use its existing discretion within the current regulatory framework on many of the matters of concern raised by the proponents. Examples include:

- considering renewable gas-related capital expenditure (JGN's forecast renewable capital expenditure proposal was excluded despite being evaluated as economic and providing a net benefit)
- operating expenditure step changes that support emissions reductions (providing JGN leak detection expenditure)
- curtailed allowances for depreciation that account for customer price impacts, adjusting the tariff variation mechanism and tariff approaches of businesses (JGN, Evoenergy and the Victorian distribution network service providers).

Additionally, JGN sought changes to its model standing offer to increase the cost-reflectivity of connections and has supported the rule change to ensure that no connections capital expenditure is socialised via entering the regulated asset base.

Whether the AER has appropriately applied the tools and the discretion available under the NGR is a separate matter, for which focus may be better served. For example, the AER has constrained depreciation schedules to provide for an arbitrarily determined price increase limit. This AER position has been subject to less testing with customers than distribution network service provider proposals on depreciation.<sup>13</sup> The outcome has been to mute price impact for the short term at the expense of long term customer impacts.

<sup>10</sup> This risk is set out in: Boston Consulting Group, [The role of gas infrastructure in the energy transition](#), June 2023.

<sup>11</sup> Future relative costs of electricity versus gas remain uncertain. Potential impacting factors could include: a global oversupply of LNG leading to low-cost gas imports, while rising transmission costs may make renewable electricity more expensive in some regions.

<sup>12</sup> For example, Colongra and Kurri Kurri gas powered generators are connected to JGN's trunk but are currently limited to operating only eight hours at a time, followed by extended periods needed to refill gas storage. To enable continuous operation and integration with storage facilities at Port Kembla Energy Terminal and Golden Beach, significant upgrades to JGN's trunk and the Eastern Gas Pipeline are necessary. Similarly, APA Group has previously announced plans for investment in gas storage to support the development of new gas powered generators in NSW and Queensland.

<sup>13</sup> In its final 2025 decision for JGN, the AER reduced JGN's revised revenue due to a change in the depreciation schedule from \$230 million to \$115 million (\$2024-25), determined by applying a 'base' real price increase limit of 0.5% for the 2025–30 period.

## 1.2 Responding to proponent assertions

The proposals advanced by the proponents rest on a series of assumptions that warrant scrutiny, as they are either unsupported or mischaracterise the current regulatory framework.

This includes:

- The interpretation of a reasonable opportunity to recover at least efficient costs
- There is no ‘transfer’ of risk to customers and networks have not ‘taken advantage’ of the rules
- Providing a broader context on the future of gas.

### 1.2.1 The revenue and pricing principles drafting was not intended to permit regulatory approaches designed to prevent recovery of certain costs

First, the proponents appear to rely on misguided interpretations of the language of the relevant revenue and pricing principle<sup>14</sup> to support the proposition that gas network service providers should limit their expectations on recovery of efficient costs.<sup>15</sup> The terms of s24 of the NGL are clear that the AEMC must take into account the revenue and pricing principle that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs incurred. We recognise the principle does not *guarantee* recovery of efficient costs. However, nor does it sanction approaches that foreclose a *reasonable opportunity* to recover the costs that have been identified as the efficient costs of performing regulated functions.

The language in the relevant revenue and pricing principle reflects the *ex ante* nature of revenue and price regulation under the NGL and NGR. It recognises that, even where a reasonable opportunity has been provided by the regulator, a network service provider may not fully recover all of its efficient costs. For example, this could be through networks having demand risk through a price cap, or through the operation of incentive mechanisms.

Whilst the wording of the principle recognises the inherent risks to cost recovery under an *ex ante* framework, there is no indication that this revenue and pricing principle was intended to permit regulatory approaches designed to prevent recovery of certain costs—for example, by excluding certain costs from a service provider’s regulated asset base. On the contrary, the principle was intended to rule out methods that would deprive a service provider of the ‘reasonable opportunity’.

### 1.2.2 There is no ‘transfer’ of risk to customers and networks have not ‘taken advantage’ of the rules

Second, changes to the depreciation schedule would not ‘transfer’<sup>16</sup> costs to customers and gas network service providers have not been ‘taking advantage’<sup>17</sup> of the rules. Changes to the depreciation schedule were envisaged and enabled within the regulatory framework as it currently exists to ensure efficient outcomes. It was put in place to support the reasonable opportunity to recover at least efficient costs.<sup>18</sup> The revenue and pricing principle to

<sup>14</sup> NGL, section 24(2). That is, that 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.

<sup>15</sup> Energy Consumers Australia, Rule change proposal, Creating Additional Criteria for the Application of Accelerated Depreciation, p.15; Justice and Equity Centre, Gas Distribution Network Rule Change Request—Asset Redundancy and Accelerated Depreciation, pp. 4, 19.

<sup>16</sup> Justice and Equity Centre, Gas Distribution Network Rule Change Request—Asset Redundancy and Accelerated Depreciation, pp. 5, 19.

<sup>17</sup> Energy Consumers Australia, Rule change proposal, Creating Additional Criteria for the Application of Accelerated Depreciation, p.15.

<sup>18</sup> It is worth noting that the possibility of positive future gas network scenarios can be consistent with changes to depreciation schedules. The increased uncertainty for each network about what actual scenario between two extreme bookends might eventuate and when this will manifest means:

- Networks would consider that the risk of each scenario is materially above zero, with the risk of scenarios that move away from the assumption of a perpetual network, more recently, increasing in likelihood.
- Prudent networks, considering current and future consumer interests, may propose (and have proposed) a range of steps now to mitigate the risks of different scenarios emerging. This includes changes to depreciation schedules, but also includes a myriad of other initiatives such as renewable gas, connections policy, and disconnections/ abolishments processes.

ensure an opportunity to recover at least efficient costs was established to avoid a key concern of policy makers at the time. This was to address the risk of underinvestment, noting its negative consequences on customers and the economy.<sup>19</sup>

The regulatory framework remains far from riskless for gas network service providers. The continued strengthening of constraints on the exercise of market power associated with customers not choosing gas might, given the negotiate-arbitrate nature of the regulatory framework, result in service providers' actual revenues being lower than what is allowed by regulators. Additionally, the existence of the rule changes means risk to the stability and predictability of the regulatory framework exists to the extent that the debate has been put on the table.

### 1.2.3 Broader context on the future of gas

Third, the proponent's narrow view of the future of gas is not reflected in recent government positions. The Commonwealth Government's 2024 *Future Gas Strategy*, which sets the long-term policy direction for gas in Australia's energy mix, affirms that "under all credible net zero scenarios, natural gas is needed through to 2050 and beyond".<sup>20</sup>

This policy direction is further reinforced by the Commonwealth Government's recently released *Energy and Electricity Sectoral Plan*.<sup>21</sup> The plan outlines the broader requirements for decarbonising Australia's energy system and acknowledges the complexity of the task ahead. It recognises that a future low-emissions energy mix will be shaped by diverse users, technological limitations, and sector-specific needs. Importantly, it underscores that no single technology can meet all objectives, and that flexibility and nuance are essential—highlighting the complementary roles of renewable electricity, low-carbon liquid fuels, renewable gases, and natural gas in achieving a balanced and resilient energy transition.

Based off historical trends, and future forecasts, the plan recognises that gas usage and its decarbonisation will vary across sectors, depending on consumer needs and constraints:

- **Consumer-led electrification** of some sectors will lead to a reduction in gas demand.
- **Others will find electrification not feasible** due to operational requirements and economic factors. These sectors will need to transition from unabated gas to renewable alternatives such as biomethane and hydrogen, carbon capture utilisation and storage, or purchase offsets.
- **In certain cases, gas usage may increase materially**, particularly where it replaces more carbon-intensive fuels like coal in electricity generation or industry. For example, BlueScope's plans to decarbonise the Port Kembla Steelworks by 60 per cent would require up to 30 PJ of extra gas annually.<sup>22</sup> The equivalent of ~30 per cent of the total volume flowing through JGN's network in NSW.
- **Gas powered generation (GPG) is critical to underpin the decarbonisation of Australia's electricity system**, and is forecast to grow as a proportion of total gas usage in the east coast gas market. GPG may be connected either directly to gas transmission pipelines, or to gas distribution networks, with JGN recently connecting the new Kurri Kurri GPG plant.

This variability means the decarbonisation pathway for gas users will be neither linear nor uniform. Jurisdictional differences—such as weather, geography, end-user composition, and socio-demographic factors—will shape how gas transitions in each region. As such the Commonwealth Government's *Energy and Electricity Sectoral Plan* contains no specific policy regarding the future of gas networks - through which gaseous molecules are delivered to Australian households, commercial and industrial users, including electricity generators. However, it does identify that the development of renewable gases – hydrogen and biomethane – as one of three policy directions required to decarbonise gas use and put Australia on the pathway to 2050. It also specifically notes that this is

<sup>19</sup> For example, the a panel member of the Productivity Commission Expert Panel who reviewed the National Access Regime in the early 2000's noted '*asymmetry arises because underinvestment in infrastructure (which might be expected if regulatory returns were too low) can, in general, be expected to have more severe consequences for the economy than excessive or otherwise inefficient investment that might occur if regulatory returns are too high*'. Euan Morton, 'Dissenting Commentary on Chapter 5 – Framework for Regulatory Decision Making' (Addendum to Expert Panel Report) (**Morton Commentary**), p 5.

<sup>20</sup> Australian Government, *Future of Gas Strategy*, May 2024. P. 4

<sup>21</sup> Australian Government, *Electricity and Energy Sector Plan*, 17 September 2025.

<sup>22</sup> BlueScope, *Climate Action Report*, September 2024, p. 28.

already occurring at scale in North America and Europe, and that biomethane can be injected directly into existing gas networks.

In NSW, JGN, which serves over 1.5 million customers across Greater Sydney and regional NSW, hauls approximately 87.5PJ of gas annually. Of this, around 69 per cent (60PJ) is used by commercial and industrial users<sup>23</sup>—many of whom it is unfeasible to electrify. These customers will require some form of gaseous energy to maintain operations and economic activity in the foreseeable future.

Recognising this challenge, the NSW Government has developed a Renewable Fuel Strategy (**RFS**) to support the uptake of low carbon fuels and enable a pathway for hard-to-electrify gas users. Recent public messaging from the team leading the RFS highlighted that 61PJ of natural gas and 78PJ of black coal in NSW are considered “hard-to-abate.”<sup>24</sup> These figures align with Jemena’s internal analysis and were used to support the Government’s upcoming renewable gas policies. This approach, however, is predicated on maintaining a viable gas network to enable this transition.

Nevertheless, with legislated net-zero targets the NSW Government has committed to lowering emissions of gas users through yet-to-be specified electrification targets, as recommended in the *Consumer Energy Resources Strategy*, and also proposed a *Gas Decarbonisation Roadmap* be delivered by late 2026. These initiatives aim to guide the State’s transition to a lower-emissions energy system by encouraging the uptake of consumer energy technologies and clarifying the future role of gas. However, the NSW Government has not publicly progressed these policy workstreams in terms of specific policy proposals that would provide clarification as to their intended form or effect on gas network viability. Moreover, there is no public policy proposal to phase out gas networks by the NSW Government.

This has been underscored by the NSW Premier Chris Minns who has declared that “gas is part of the energy mix of the future”.<sup>25</sup> He has also ruled out mandating household electrification, emphasised consumer choice and the importance of new natural gas supply—particularly through the Narrabri gas project—to support industrial needs and ensure energy reliability during the transition.

As Australia progresses toward its net-zero goals, the future make-up of gas usage remains unresolved. However, the need for both natural and renewable gas is well understood, and the Commonwealth and NSW Governments have recognised this through their respective strategies and policies. This broad policy direction is at odds with the Australian Capital Territory (**ACT**)<sup>26</sup>, the only Australian jurisdiction that has announced a policy to phase out its existing gas networks, albeit the practical framework for retiring or repurposing network assets has yet to be developed.<sup>27</sup>

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<sup>23</sup> SGSPAA, [A Sustainable Transition | SGSPAA Sustainability Report 2024](#), p 34.

<sup>24</sup> NSW Government, Department of Climate Change, Energy, the Environment and Water, [Industrial decarbonisation action in NSW](#), p. 8.

<sup>25</sup> See link: [NSW Premier Chris Minns rules out state following Victoria's gas ban](#).

<sup>26</sup> In the case of the ACT, it is in a unique situation for a gas distribution network in Australia where they have no large industrial and gas power generation customers, and the gas and electricity distribution networks have common (and partial government) ownership. We recognise the Victorian Government has made decisions in relation to phasing out new gas connections for new homes and new commercial buildings as well as supporting gas appliance replacement.

<sup>27</sup> ACT Government. (2024). *Gas connection decommissioning (abolishment) technical review*.

## 2. Depreciation and capital redundancy rule changes should not be made

The proposed depreciation and capital redundancy rule changes would undermine investment and is not consistent with the NGO.

This section covers Jemena's response to AEMC:

- Question 4: Does the current framework effectively manage and allocate risk and costs between consumers and network service providers in the context of uncertain demand?
- Question 5: How does ECA's proposal impact the recovery of capital costs for new and existing assets?
- Question 6: How does JEC's proposal impact the recovery of capital costs?

### 2.1 Risk to investment and how the proposals fail to meet the NGO

The revenue and pricing principles include that a scheme pipeline service provider is provided with a reasonable opportunity to recover at least efficient costs.<sup>28</sup> As noted by the Full Court of the Federal Court, the role of the pricing principles is '*not so much to prescribe what should happen in a particular situation, but to rule out approaches and methodologies which would be inappropriate*'.<sup>29</sup> In addition, there is legal precedent that the revenue and pricing principle requires the AEMC as the rule maker and the regulators to 'err on the side of allowing at least the recovery of efficient costs'.<sup>30</sup>

The two proposed rule changes related to depreciation and capital redundancy fall into the category of an inappropriate approach to be ruled out. They seek to require gas network service providers to trade-off between efficient (and often customer-supported<sup>31</sup>) depreciation schedules addressing intergenerational equity concerns and the return of efficiently invested capital expenditure. This presents a violation of a foundational 'rule of law' economics principle that provides stability and predictability of the regulatory framework and therefore supports investment, driving economic growth. Firms, individuals, and private investors (including governments investing in other jurisdictions) must be assured that their property is protected by law. Failure to do so results in the investor shortage often apparent in developing countries.

Further, there is well-established economics literature that notes a key task of regulation is to protect the sunk costs of a regulated firm. For example, the economists Spiller and Tommasi note:<sup>32</sup>

*"the overarching problem driving the regulation of utilities whether private or public, and the issue that politicians have to deal with, is how to limit government opportunism, understood as the incentives politicians have to expropriate – once the investments are made- the utilities quasi rents, whether under public or private ownership, in order to garner political support."*

Importantly, the harm of breaking the established stable and predictable regulatory compact spreads beyond investment in gas networks the subject of these rule changes, and should be a concern for governments seeking to attract private investment to support the broader energy transition.<sup>33</sup> Jemena supports the Australian Pipelines & Gas Association submission that sets out the importance of the regulatory compact and risk to investment in detail.

<sup>28</sup> NGL, section 24(2).

<sup>29</sup> *Glencore Coal Assets Australia Pty Ltd v Australian Competition Tribunal* (2020) 280 FCR 194, 215 at [85]; [2020] FCA 145.

<sup>30</sup> *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009)* [2009] ACompT 8, at [81]-[82].

<sup>31</sup> JGN, *2025 Plan*, June 2024, p. 35.

<sup>32</sup> Spiller, P.T., Tommasi, M. (2008). *The Institutions of Regulation: An Application to Public Utilities*. In: Ménard, C., Shirley, M.M. (eds) *Handbook of New Institutional Economics*. Springer, Berlin, Heidelberg, pp. 515–543.

<sup>33</sup> Heightened risk will increase required rates of return for new investment, not only in gas, but in electricity. Australia needs to compete for capital with global markets.

The AEMC’s assessment of international practice<sup>34</sup> also supports avoiding this type of approach. The relevance of instances cited in Estonia, Slovakia, Sweden and Italy where some level of asset stranding is not compensated for should be read in the context of:

- The source information being from surveys that only considered those countries responses to physical asset stranding (and not economic asset stranding)
- Two networks (Estonia and Slovakia) being government owned (thus limiting the flow on impact this would have to private investment)
- These being transmission gas assets.

The elements of the two depreciation rule changes that rule out the possibility of full return of efficiently invested capital expenditure (via requiring write downs to the regulated asset base) would not provide a reasonable opportunity to recover at least efficient costs and result in the negative NPV of past and future investments. Consistent with the Full Court approach, the AEMC should be able to rule these out as inappropriate methodologies not consistent with the NGO. Doing so at the earliest opportunity avoids risking sending signals to existing investors and the broader finance sector that the understood regulatory compact is subject to reconsideration.

## 2.2 Making changes to depreciation schedules conditional on other actions does not promote the NGO

Both the ECA and JEC proposals include making changes to the depreciation schedule conditional on the gas network service provider completing or meeting additional criteria (for example, publishing a planning report<sup>35</sup> or undertaking a redundancy assessment<sup>36</sup>). This requires AEMC assessment of whether placing conditions on acceleration of depreciation effectively *deprives* service providers of the required opportunity to recover efficient costs and whether it could create other perverse effects on the NGO.

For example, when looking at depreciation, the NGO is best achieved via networks proposing, and the AER approving, an efficient depreciation schedule that reflects a best view of economic asset lives. This supports the NGO via the resulting efficient price signal for customers driving the efficient use of the network.

Conversely, if the rules actively prevent (such as via JEC’s alternative solution to outright prohibit changes to the depreciation schedule) or even hinder the efficient depreciation schedule being put in place, with this generally resulting in lower-than-efficient depreciation, the resulting lower price will signal to customers to use the network at a higher rate than is efficient. Therefore, not promoting the NGO.

Perverse to the proponents’ desired impact of the rule change, this would reduce consumers price incentives to electrify. This also offends the revenue and pricing principle seeking efficient utilisation.<sup>37</sup>

The AEMC assessment criteria needs to include consideration of the efficient utilisation of the network and the associated revenue and pricing principle (refer section 6).

## 2.3 Redundant asset rule

It’s not clear the current redundant asset rule (NGR rule 85) was ever meant to deal with decommissioning whole networks as the proponent seeks to expand it into. Rule 85 caters for assets that no longer contribute “in any way” to the provision of services. This is likely to be a high threshold to meet where an asset no longer contributes in any way either physically or economically.

<sup>34</sup> Consultation Paper, Appendix A.

<sup>35</sup> Energy Consumers Australia, Rule change proposal, Creating Additional Criteria for the Application of Accelerated Depreciation, p.19.

<sup>36</sup> Justice and Equity Centre, Gas Distribution Network Rule Change Request—Asset Redundancy and Accelerated Depreciation, pp. 21-23.

<sup>37</sup> NGL section 24(7). That is, 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.

Rule 85 is also constructed in a way (with respect to the timing to give it effect) to imply an expectation that the AER should consider corresponding actions when enacting it. That is, removing redundant assets from the regulated asset base should be considered along with compensation in other mechanisms (e.g. the rate of return or via shorter asset lives/depreciation). Failure to do so would need to be considered together with whether this would offend the revenue and pricing principles as the opportunity to recover those costs has been removed.

The existence of rule 85 to accommodate limited scenarios should not be inferred as policy-makers' view that stranding (or potentially stranding) of the full regulated asset base should occur and be shared in a particular way. That policy decision has not been made. If the policy is to be considered by governments, this should be done so recognising all the potential broader investment and economic risks, as well as the risk that reconsidering the entrenched and understood regulatory compact in itself sends signals to investors and the broader finance sector. Further, rule 85 cannot practically apply to wholesale network decommissioning without a range of commercial, legal and practical steps first occurring. For example, customers would first need to disconnect their gas connections and electrify their homes. Until this happens – or a clear policy trigger is established – it is premature to invoke rule 85 as a mechanism for network-wide decommissioning.

JEC's proposed approach to require an assessment of anticipated redundant assets would be fraught with issues. First is the risk to the stability and predictability of the regulatory framework previously identified. But other questions arise such as:

- How is a thirty-year forecast of redundant assets prepared in practice, noting the Australian Energy Market Operator's Gas Statement of Opportunities forecasts only to twenty years?
- Are actions taken in one access arrangement, based on a forecast set of redundant assets, to be later reversed if those assets remain useful or are later anticipated to be useful?
- Any such assessments are likely to be highly speculative and involve a significant degree of regulatory error, with material consequences for energy infrastructure investment and consumers. How can this be managed?

## 2.4 Risk of asset underutilisation

We do not 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. The existing regulatory framework already provides practical tools to address potential underutilisation and intergenerational cost allocation, as demonstrated by the AER's acceptance of changes to depreciation schedules, which explicitly manages timing of cost recovery between present and future consumers. The Australian Competition and Consumer Commission (ACCC) and AER have consistently maintained that asset stranding risk should not be reflected in the weighted average cost of capital (WACC), but instead addressed through cash flow adjustments—primarily via changes to the depreciation schedule. This position was articulated by the ACCC in its 2002 Amadeus Gas Pipeline access arrangement decision<sup>38</sup> and has been upheld by the AER in subsequent reviews.<sup>39</sup>

The AER's 2013 and 2018 WACC reviews reaffirmed the use of a single WACC across all regulated businesses, noting that firm-specific stranding risks are managed through mechanisms such as changes to depreciation schedules. The 2022 Rate of Return Instrument reiterated this approach:<sup>40</sup>

*Therefore, we continue to adopt a single rate for gas and electricity networks. We maintain the view that asset stranding risks faced by gas networks should be addressed through the broader regulatory framework (for example, accelerated depreciation)*

Investors have relied on the AER's position that changes to depreciation schedules would be used to manage stranding risk. By not increasing the WACC or providing an operating expenditure allowance for this risk, customers have benefited from lower gas tariffs in the past, with the understanding that tariffs would rise if

<sup>38</sup> ACCC, *Final Decision – Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline*, 4 December 2002, pp. vii, 91.

<sup>39</sup> AER, *Rate of Return Instrument: Explanatory Statement*, February 2023, sections 2.4.1 and 8.3.5. This position has been consistently adopted for over 20 years, since the ACCC's 2001 access arrangement decision for the Amadeus Gas Pipeline.

<sup>40</sup> AER, *Rate of Return Instrument – Explanatory Statement*, February 2023, p. 184.

stranding risk increases or materialised. This regulatory compact underpinned investment decisions; altering it retrospectively would result in a negative NPV for those investments.

### 3. Capital expenditure criteria rule changes largely unworkable

The majority of the proposed capital expenditure criteria rule changes are unworkable when assessed against the NGO and revenue and pricing principles.

This section covers Jemena's response to AEMC:

- Question 2: What changes, if any, should be made to the NGR capital expenditure criteria
- Question 3: Are any changes required for operating expenditure

Jemena has material concerns with the elements of the rule change that seek to:

- Require the regulator to assure itself that the service provider has acted prudently in previous investment decisions prior to approving replacement expenditure—there are multiple issues with this type of 'look back test'
- Remove the ability for capital expenditure that improves safety to be conforming capital expenditure—which may conflict with other legislative or regulatory requirements to improve safety
- Bring an electricity mindset to reliability and demand management, which is inappropriate for gas networks
- Actively exclude capital expenditure that supports renewable gas from being considered as part of reference services—where it cannot be demonstrated that removing AER discretion better achieves the NGO
- Adjust the supply of services in NGR rule 79(2) to include the provision of energy services by other means, whether by the service provider or another party—it is not clear how this would work in practice and the approach would not be consistent with the Ministerial Council decision to retain the NGO and National Electricity Objective (**NEO**) as related to 'consumers of gas' and 'consumers of electricity' respectively (as opposed to 'consumers of energy').
- Adjust the definition of operating expenditure to exclude expenditure that supports demand—where:
  - removing expenditure that supports demand growth, combined with the potential for a gas network service provider to be regulated under a price cap (or hybrid) means a network service provider is being required to manage demand risk without the key means to manage that risk
  - it remains in customers' interests to spread gas network service providers' fixed costs across as many customers as possible.

The areas identified by the ECA are not 'gaps' in the existing framework. In contrast, the proposals would actually make the framework less flexible by prescribing the application of regulation by the AER in cases where it today has discretion. These are discussed in turn below.

#### 3.1 Ability for the AER to look back at past investment decisions is unworkable

The ECA proposes that there be "a requirement for the regulator to assure itself that the service provider has acted prudently in its previous investment decisions before allowing capex to replace assets" within rule 79.

There are several issues with this concept of a "Look Back Test":

- Conflict with capital expenditure for safety
- Conflict with the revenue and pricing principles
- It would not promote the NGO
- Practical issues.

### 3.1.1 Conflict with capital expenditure for safety

Depending on how the rule is drafted, this proposal could effectively prevent the AER from approving capital expenditure that is required to maintain network safety<sup>41</sup> and reliability and/or to meet expected demand.

If the AER considers that the service provider has not acted prudently in the past, then the AER may (or may be required to) refuse to approve the replacement capital expenditure. As examples of where a service provider might be deemed to have acted imprudently, ECA refers to “assets that were poorly sited/installed/configured or where the original equipment manufacturer has ceased to produce replacements and spare parts”.

In practice, this may require the AER to assess actions or decisions taken many decades ago regarding asset location, configuration or choice of the original equipment manufacturer. If the AER deems these past decisions imprudent (with hindsight), the AER may be required to disallow the replacement capital expenditure even if it is necessary to maintain network safety, reliability or capacity to meet demand for reference services.

As a result, this could create conflict with the existing capital expenditure criteria which provide that capital expenditure will be ‘justifiable’ if it is necessary to maintain safety, service integrity and/or capacity to meet service demand.

### 3.1.2 Conflict with the revenue and pricing principles

The current capital expenditure criteria align with the revenue and pricing principles and NGO as they provide for recovery of costs that are necessary to maintain quality, safety, reliability and security of supply. Introducing a ‘look back test’ would potentially conflict with the existing criteria for justification of capital expenditure. The AER may be required to disallow replacement expenditure under the ‘look back test’, notwithstanding that it may be “justified” under other criteria.

Such a rule would conflict with the revenue and pricing principle that a scheme pipeline service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services and complying with regulatory obligation.

Insofar as the ECA’s proposed rule would *prevent* the AER approving replacement capital expenditure that is necessary to maintain the safe and reliable delivery of reference services, then it would be in direct conflict with revenue and pricing principles. If necessary replacement capital expenditure cannot be approved by the AER as conforming, then the service provider will not have a reasonable opportunity to recover the efficient costs of continuing to supply reference services.

### 3.1.3 Rule would not promote the NGO

Such a rule would not contribute to the achievement of the NGO if it means that service providers are unable to recover their efficient costs.

Management of gas network service providers are extremely unlikely to compromise on safety given the range of legislative, regulatory and licence obligations they face, and impacts to the service provider’s social licence (which, in turn, are a reflection of community expectations in relation to the public safety and energy infrastructure). If network service providers are deprived of a reasonable opportunity to recover the efficient costs of investing to maintain network safety, reliability and security of supply, then they become NPV negative, creating a perverse incentive to avoid such investment. Despite management approaches to safety, this would be an undesirable feature of the regime, which should not provide incentives that risk service degradation and potential safety risks to the detriment of the long-term interests of consumers. In reality, safety is likely to be maintained and the outcome is the deprivation of the opportunity to recover the efficient costs associated with that safety-related investment.

More broadly, the proposed rule would likely be damaging to investor confidence by creating a concerning precedent that may deter broader energy sector investment in Australia, insofar as it contemplates revisiting past

<sup>41</sup> As required under Gas Supply Act 1996 and Regulations (including the Australian Safety Standards) and JGN’s reticulator’s authorisation.

regulatory decisions. The AER already has the ability to assess whether capital expenditure is conforming. A rule such as proposed would effectively punish networks for what, in hindsight is revealed to be, the mistake or misjudgement of a regulator. Existing pipeline capital bases comprise assets that were either included by regulators in initial capital bases upon commencement of regulation (typically depreciated optimised replacement cost values) or have been approved for addition as conforming capital expenditure. In effect, all of this capital has previously been accepted by the AER as prudent and necessary for the provision of regulated services.

The proposed 'look back test' would require the AER to revisit and potentially change those past decisions. Allowing the AER to revisit past regulatory decisions would call into question the certainty of decision making under the NGR (and by extension, the National Electricity Rules), which would have a chilling effect on future investment in gas networks. It would also diminish the precedent value of AER regulatory decisions generally, which ordinarily give market participants some certainty as to how the AER will exercise its discretion in decision making – including in relation to understanding how the AER assesses the prudence and efficiency of proposed capital expenditure.

### 3.1.4 Practical issues

There are significant practical difficulties in drafting a rule that requires the AER to reassess, in hindsight, already approved and incurred capital expenditure. There are many factors the AER would need to balance when exercising discretion to determine whether capital expenditure has been prudently incurred by a network in developing and maintaining a certain asset over time. Issues to be resolved would likely include:

- How far back in time can the AER look? Does the 'look back test' extend back to when assets were under different ownership (in some cases under Government ownership) and investment might have been informed by different policy considerations?
- When assessing decisions taken several decades in the past (e.g. to configure assets in a particular way or in particular locations), the network service provider may not have access to all the relevant information informing that decision for the AER to be certain it can understand the context at the time? There would be significant costs to collect and for the AER to review the available information within the price review timeframes.
- When a network has invested in the same asset across multiple access arrangement periods (e.g. initially configured in a particular way then augmented to meet demand), what regulatory decision(s) does the AER need to consider and give primacy to?
- What makes a site poorly sited/installed/configured etc such that a network's past investment decisions could be deemed in hindsight to be not prudent and efficient?

Most importantly, the AER would need to properly address the hindsight bias inherent in applying the 'look back test'. In hindsight, it may appear inevitable that assets should have been configured in a different way, in a different location or using different technology. However, this type of hindsight bias would need to be removed from any assessment of whether investment decisions were prudent at the time.

## 3.2 Proposed change to remove capital expenditure that improves safety

ECA proposes that rule 79(2)(c) is updated to remove the words "*and improve*" from clause (i) of the subrule – noting that it remains essential to maintain safety.

It is unworkable to expect safety levels to be constantly maintained at a single level into perpetuity. The public expects safety standards to continuously improve. The most ubiquitous example of this is in relation to car safety, but it applies across the spectrum of consumables and infrastructure that the public interacts with.

The obligation to maintain a safe network under the *Gas Supply (Safety and Network Management) Regulation 2022* is absolute.<sup>42</sup> Further, the Australian Standards<sup>43</sup> hold gas network service providers to the standards of:

- ‘as low as reasonably practicable’ where risks should be reduced to a point where the cost of further reduction is "grossly disproportionate" to the benefit gained. Under this mechanism, if there is an incremental benefit beyond the incremental cost of a safety measure, gas network service providers should be expected to implement it.
- ‘as far as reasonably practicable’ in some instances, where economic factors are not considered due to the potential negative consequences of the risk (often in the case of the potential safety of the public or employees).

These are not static as technology and industry practices evolve. Gas network service providers will continue to invest to meet the expected safety levels and the mandated Australian Standards. However, under the proposal they would only be able to recover capital expenditure that *maintains* the pre-existing safety levels. This would hinder network service providers’ ability to properly manage safety, as well as create uncertainty around liability for safety incidents (likely increasing insurance costs). This would not meet the revenue and pricing principle to recover at least efficient costs and would not support the NGO with regard to promoting efficient investment related to safety. It would not be in customers’ long-term interests for gas network service providers to face incentives to spend below the efficient level of capital expenditure.

Practically, it would be difficult to split the capital expenditure between that which was required to maintain safety at an arbitrary single point in time level versus that which led to safety improvements beyond that.

### 3.3 Reliability

ECA propose that rule 79 is updated so that there is “*clarity that the costs of capex to maintain the integrity of the network must be weighed against the value that customers place on avoiding loss of supply*”.

It is important to understand what reliability means on a gas network, especially if bringing an electricity mindset to these rule changes. With gas, interruptions to supply can be a safety issue, whereas electricity generally fails safe. Reestablishing gas supply requires substantial fieldwork, including individual gas supply technician attendance at each site requiring ‘making-safe’ by turning off at the meter and subsequent physical checks to ensure the safe reconnection once gas is reflowing. This has significant time and cost implications not apparent in electricity. It also means upfront investment in reliability can be significantly more efficient than the operating expenditure requirements to deal with bringing customers back onto supply.

It is not clear what the proposed additional criteria would practically mean and what gas network service providers would do differently. Replacement capital expenditure on gas networks is largely driven by safety (i.e. avoiding leaks) consistent with Australian Standards and regulatory obligations. The failure of some assets creates safety risks, and it is these risks, rather than the associated loss of supply to customers, that is the real investment driver.

In terms of customers’ views on reliability, we know that different customers place different values on reliability. For large industrial customers, reliability can have a significant value. If some large customers were to lose supply, total and permanent plant closure may result. Some can take multiple days to restart operations and production after shutdowns, with significant commercial implications. For others, supply is critical to support human life (eg hospitals and nursing homes). Some may be subject to damage to equipment (eg glass producers). Many large customers may not have experienced gas outages nor understand the full impacts of going off supply and the value they would subsequently place on reliability.

We also know energy security is important to many residential customers. To lose gas supply for unknown periods will impact on quality of life, especially where gas is the only source for cooking, heating and water. This is especially the case in cooler weather where the length of time to bring customers back on supply would also be

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<sup>42</sup> Section 7(1), *Gas Supply (Safety and Network Management) Regulation 2022*.

<sup>43</sup> For JGN this includes the Gas supply (safety and network management) regulation 2022 and Standard 4564 (networks) and Standard 2885 (pipelines).

of concern.<sup>44</sup> From a policy perspective, life support obligations apply equally to gas and electricity customers, indicating no less value is currently placed on gas reliability.

### 3.4 Proposed change to exclude capital expenditure related to renewable gas

ECA proposes that rule 79 be amended to provide for “*the exclusion of capex on preparing to transport renewable fuels from reference services, so that such costs (to the extent they are conforming capex) can only be recovered from customers who wish to take renewable fuels in the future*”.<sup>45</sup>

This element of the rule change is unworkable, insofar as it seeks to exclude transportation of renewable gas from the scope of reference services for which capital expenditure may be recovered through reference tariffs. Whether costs associated with transporting renewable gas qualify as conforming capital expenditure – and hence whether these costs may be recovered through tariffs for reference services – turns on whether transportation of renewable gas is within the scope of reference services.

The scope of conforming capital expenditure is linked to the scope of reference services, as determined by the AER under NGR rule 47A. Once the AER has defined the scope of reference services for an access arrangement period, then the service provider must be provided with a reasonable opportunity to recover the efficient costs of providing those reference services.<sup>46</sup> If the AER defines reference services in a way that excludes transportation of renewable gas, then costs for transporting renewable gas would not be recoverable under (current) rule 79. However, if the AER at some point defines a reference service for transporting renewable gas, then these costs would need to be recoverable through reference tariffs.

The rules cannot restrict the AER’s discretion in determining what is or is not a reference service. Under the NGL, a reference service “means a pipeline service specified by, or determined or approved by the AER under, the Rules as a reference service”. This exercise needs to be carried out by the AER at the time the AER makes its decision on what the reference services are for a regulated network’s forthcoming access arrangement, having regard to matters including the reference service factors in subrule 47A(15).

The NGL contemplates that a “pipeline service”, and therefore a “reference service” determined by the AER, may be a service for transportation of renewable gas. A pipeline service means a service provided by means of a pipeline (including haulage) and a “pipeline” means a pipe or system of pipes for the haulage of “covered gas”. “Covered gas” (transportation of which may be a “pipeline service”) includes a primary gas which expressly includes renewable gas such as biomethane hydrogen.<sup>47</sup> This definition (and the extension of the economic regulatory framework to renewable gases) was considered only recently and at length by Energy Ministers when making these changes to the NGL. It is also consistent with the Australian Government’s Electricity and Energy Sector Plan which cites the development of Renewable Gases as one of three pathways to 2050.<sup>48</sup>

Ambitious emissions targets have been set by the Commonwealth Government. Excluding capital expenditure to prepare for renewable gas restricts the ability of the gas network service providers, and wider customer base, to support decarbonisation. It is clear, given the emissions targets, and climate change, that supporting reduced emissions is for the benefit and long-term interests of all customers, and the general community. The development of renewable gas markets will also require investment to support the longer term operation of the gas network. This would provide benefit for all customers who remain connected, especially as the percentage blend of renewable gas increases.

Given the NGL explicitly includes the lowering of emissions, excluding capital expenditure required to transport renewable gas risks undermining the AER’s ability to make decisions which are consistent with the NGL.

In particular, curtailing the AER’s current ability to determine what is or is not a reference service would restrict the AER from being able to adapt how it defines reference services over time – including, importantly, as new

<sup>44</sup> For example, the Bathurst gas outages in 2022 left 12,000 customers off supply for up to 6 days with over 100 personnel across Jemena, police and SES required to reconnect safely.

<sup>45</sup> Energy Consumers Australia, Rule change proposal, Amending the Criteria for approving capital, p.19.

<sup>46</sup> NGL, section 24(2).

<sup>47</sup> NGL, section 2.

<sup>48</sup> Australian Government, [Electricity and Energy Sector Plan](#), p. 5

technologies develop. Ultimately, maintaining the AER discretion / flexibility to consider whether reference services should include transport of renewable gas at some point in the future (based on evidence available at that time) would better achieve the NGO.

### 3.5 Provision of energy services by other means was previously considered unworkable by the Energy and Climate Change Ministerial Council

The ECA suggest that:<sup>49</sup>

*...amendments are required... to consider alternatives to investment in replacement or new network equipment, including where relevant the provision of energy services by other means.*

The ECA appears to give this effect through amending rule 79(2)(c)(v) to clarify that the ‘supply of services’ could include the provision of energy services by other means, whether by the service provider or another party.

The implication of the proposed drafting appears to be that gas network service providers would be able to have capital expenditure enter their regulated asset base where that investment was for energy services other than gas, which might, by implication, include electricity investments. It’s not clear if this is the ECA’s intent, or whether they are seeking for gas network service providers to start considering electrification alternatives.

Either approach would require substantial development and is likely unworkable.

The Energy and Climate Change Ministerial Council recently considered the issue of holistic consideration of electricity and gas and concluded that should be undertaken via coordinated planning rather than a legislative process. The Ministerial Council noted:<sup>50</sup>

*Appropriate holistic consideration of electricity and gas decisions remains an important issue moving forward and will be considered outside of this legislative process, noting Energy Ministers have identified ‘coordinating gas and electricity planning’ as a priority theme under the National Energy Transformation Partnership.*

Further, when introducing the emissions reductions target into the NGO and NEO, the Ministerial Council chose not to replace ‘consumers of electricity’ or ‘consumers of gas’ in the electricity and gas objectives respectively, to ‘consumers of energy’. The Ministerial Council noted that the proposed amendment:<sup>51</sup>

*‘was designed to facilitate holistic consideration of electricity and gas when applying the new emissions objective and reflect the increasing interconnection between these two sectors’.*

However, the Ministerial Council subsequently noted that there were:<sup>52</sup>

*‘substantial concerns about the potential unintended consequences from the ‘consumers of energy’ amendments, particularly if they extended beyond the emissions arm of the objectives (i.e., to price, safety, reliability, quality, security etc)’.*

The Ministerial Council noted concerns with increasing ambiguity and complexity of market bodies’ decision-making, and result in information asymmetry for market participants that are inexperienced in considering cross-sectoral impacts between gas and electricity.

The Ministerial Council also considered changing the ‘supply of electricity’ and ‘supply of gas’ in the electricity and gas objectives respectively with ‘supply of energy’. However, chose not to make any change on the basis that:<sup>53</sup>

<sup>49</sup> Energy Consumers Australia, Rule change proposal, Creating Additional Criteria for the Application of Accelerated Depreciation, p.19.

<sup>50</sup> Energy and Climate Change Ministerial Council, *Incorporating an emissions reduction objective into the national energy objective*, Information Paper, May 2023, p. 9.

<sup>51</sup> Ibid.

<sup>52</sup> Ibid.

<sup>53</sup> Ibid.

*‘these may empower market bodies to ‘pick winners’ in the transition, result in information asymmetry for gas and electricity producers, and increase ambiguity for these reforms’.*

The ECA have not offered any new materials to alleviate the concerns raised by the Ministerial Council or how this would work with the National Energy Transformation Partnership. The proposed approach to consider alternatives to gas network investment, is not consistent with the proposal to rule out renewable related capital expenditure as one is seeking broad consideration of options and the other is ruling one out, meaning the NGR would be picking winners.

The relevant proposal should, therefore, not be made.

## 3.6 Operating expenditure

### 3.6.1.1 Proposed change to the definition of operating expenditure

The ECA proposes to remove from the operating expenditure definition any expenditure related to increasing long-term demand of pipeline services.

This creates an immediate tension with the NGO. Despite any situation that may arise in the future where network connection numbers reduce, it remains in gas customers’ interests to spread the fixed costs of the network across as many customers as possible. Gas network service providers still need to optimise the network and ensure efficient utilisation. This is especially important in areas that include hard-to-electrify customers and those where the network is expected to have a long and critical future in order to support the Commonwealth or State government’s achieve their emissions reduction targets. Gas’ role in energy transition is critical to the least cost pathway to support renewables and enable the retirement of coal generation.<sup>54</sup> Gas network service providers should have the ability to market where this ensures optimised and efficient utilisation.

Consequently, both the operating expenditure definition, as well as rule 91 (operating expenditure criteria), remain fit-for-purpose – they require operating expenditure to be prudent and efficient, and to deliver services in a way that is consistent with achieving the NGO.

Importantly, gas distribution networks have largely been regulated under a price cap to provide incentive to manage demand risk in a way that supports connecting more customers. We note that many groups who support electrification have voiced strong support for price caps remaining, with the AER adopting hybrid models in some circumstances.<sup>55</sup>

This highlights a fundamental policy tension—is the policy position to prioritise insulating consumers from demand risk (by retaining price caps for gas distribution networks) or discouraging gas use?

It would be unreasonable to expose gas network service providers to demand risk while simultaneously restricting their ability to manage that risk through demand stimulation. This creates a one-sided outcome, where government or regulator intervention effectively forces business contraction without addressing compensation. Such an approach could be construed as a de facto acquisition of property and not present a reasonable opportunity to recover at least efficient costs. This raises similar concerns for the stability and predictability of the regulatory framework discussed in section 2 above. It would also have the perverse outcome of preventing emission reduction in the case of coal to gas fuel switching or gas powered generation.

### 3.6.1.2 Decommissioning costs and regulatory asset base indexation

Jemena supports broader consideration of how decommissioning costs are to be dealt with should the assumption of networks existing into perpetuity be re-examined by government policymakers. This may include some readying of the NGR to support this within operational expenditure. This would enable these costs to be included in forecasts from the point that jurisdictional policy on decommissioning becomes clearer. Should jurisdictional policy framework change so that a pathway for strategic decommissioning arises, these costs should be accommodated

<sup>54</sup> Australian Energy Market Operator, [2024 Integrated System Plan](#), p. 33

<sup>55</sup> Including for JGN in our 2025-30 access arrangement period.

for within the regulatory framework. Indeed, the earlier that decommissioning provisions are set, the lower the impact on future customers.

Accommodating decommissioning should be considered in parallel with the appropriate indexation of the regulated asset base. Inflation compensation on the portion of the regulated asset base that ends up being decommissioned or stranded will never be recovered by investors. The AEMC may need to give consideration to whether the real rate of return approach is consistent within the evolving gas framework.

## 4. Planning requirements

The information sought in planning rule change is better led by jurisdictional requirements following future of gas network policy decisions. Poorly targeted information disclosure requirements add administrative burden for no benefit, with the Part 10 disclosure requirements for scheme pipelines being a recent example.

This section covers Jemena's response to AEMC:

- Question 7: Are new planning requirements necessary?

Jemena considers that any additional information provision requirements would be most efficient if focused on the access arrangement review process.

ECA is seeking information to support a coordinated approach to reduced gas use, assess alternatives to capital investment (e.g. demand management), and strategically decommission the gas network in coordination with the electricity network.

It is questionable whether such requirements would deliver net benefits to customers (i.e. of savings due to more efficient investment decision making) in practice, where:

- Discussion on decommissioning the gas network needs to begin with the jurisdictional policy, which has not been set out in Commonwealth, State or Territory jurisdictions with the exception of the ACT. As the AEMC have noted, this would be subject to specific jurisdictional planning assessments and consultation frameworks, plus the relevant information requirements those entail.
- A gas network service provider has no remit or ability to force individual customers to disconnect from the gas network—in fact, there are multiple provisions across the Gas Supply Act 1996 and Regulations, JGN's reticulator's authorisation, the National Energy Retail Law and the National Energy Retail Rules that restrict gas service providers from interrupting and disconnecting customers or unilaterally shutting down parts of the network. It is therefore not possible for gas network service providers to rely on the cessation of supply to customers as a means of avoiding network expenditure.
- Requirements for network operators to engage in joint planning or other forms of collaboration involve direct costs to operators, which are ultimately borne by consumers. As above, where neither the gas or electricity network operator has the ability to force individual customers to use one energy source and not the other, the results of any such planning may not be realisable in practice.
- A gas network service provider (and the electricity network operator) have a poor ability to accurately forecast the likelihood of an individual customer (or groups of customers in particular geographic areas) disconnecting from the gas network—especially to pinpoint this within a 30-year period as per the JEC proposal on depreciation and capital redundancy. In reality, the customer making the decision knows first, then the electricity network, who has more granular data, seeing the increased loads at more frequent metering intervals may become aware—all before the gas network service provider is aware.
- The concept of demand management as an alternative to asset replacement makes little sense within a gas network. There needs to be a gas lens rather than an electricity lens applied here as it is not the same issue being managed. The gas network does not need to be built to meet instantaneous demand (including by location) like in electricity. The gas network is designed to accommodate peak loads, with line-pack able to manage most within-day movements. There is no central control over loads (such as network ability to turn off appliances).<sup>56</sup> There is therefore little opportunity for capital expenditure savings from seeking demand management solutions and it is not clear what demand management options the ECA considers can be identified.

<sup>56</sup> JGN does have the ability to call upon certain large customer demand response, although this has infrequently been required. And those large customers who provide this first response benefit from a lower tariff.

- Rules that seek to include consideration of these elements provide no benefit and only add unnecessary administrative cost. This is especially the case where information may not currently exist or not exist at the level of granularity sought.

The AEMC has noted that “*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*”. This is an important consideration and JGN supports the AEMC giving careful consideration to what is already available and what is considered beneficial.

There is already transparency over a business’ forecast capital expenditure through the access arrangement process, including requirements for the business to submit sufficient information to the AER to justify its capital expenditure forecast and for only confidential information (which is strictly and quite narrowly defined by the AER’s confidentiality guideline) to be withheld from stakeholder consultation. This is in addition to information shared by the network as part of its customer engagement programs.

The AEMC should avoid information requirements that impose costs on businesses, and ultimately customers when there are limited benefits, such as has occurred recently for Part 10 disclosures for scheme distribution pipelines.<sup>57</sup>

Jemena supports access arrangement reviews that provide for longer range forecasts (demand and expenditure) in the form of scenarios beyond the duration of the immediate review period. It would mean both the long- and short-term forecasts are being prepared in the same environment with similar assumptions, avoiding potential conflicting sets of assumptions or inputs.

These longer-range scenarios being provided at each access arrangement review are becoming common practice (for example, JGN provide future of gas scenarios and modelling<sup>58</sup> that were a significant part of our access arrangement engagement program). While specific rules have not been required for these to emerge, it may be that rule guidance can help target these better toward customer preferences, expectations and needs. It is also important to note in relation to JEC’s capital redundancy rule change that the scenarios will ipso facto be varied and, therefore, not a reasonable basis for making current decisions on asset stranding and write-downs.

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<sup>57</sup> The recent introduction of Part 10 reporting for scheme pipelines in the NGR has resulted in a number of disclosure requirements for scheme pipeline distributors that demonstrably have no benefit to any party, but require significant burden to provide to the required standard. This includes duplication of information provision requirements from regulatory information notices such as demand (consumption), revenue contributions, financial data, but also non-useful or nonsensical information for distribution networks (that is intended for non-scheme transmission pipelines) such as firm capacity, capital expenditure greater than 5 percent of construction costs, and a non-indexed asset base.

<sup>58</sup> JGN 2025 Plan, Chapter 4 Responding to the Energy Transition; JGN 2025 Plan, Attachment 7.8M - Future of gas model - June 2024. Available here: <https://www.aer.gov.au/industry/registers/access-arrangements/jemena-gas-networks-nsw-access-arrangement-2025-30/proposal>

## 5. Interrelated aspects of the economic regulatory framework

Jemena supports longer range forecasts as part of access arrangement resets (as have already emerged) and an assessment of whether to bring the tariff variation mechanism into the reference service proposal.

This section covers Jemena's response to AEMC:

- Questions 8-14.

### 5.1 Extended demand and expenditure forecasts (Question 8)

As noted in section 4, JGN supports access arrangement resets that provide for longer range forecasts (demand and expenditure) in the form of scenarios beyond the duration of the immediate reset. Rule guidance has not been required for these to emerge, but could support ensuring these are best targeted at meeting customer needs.

### 5.2 Bringing forward the tariff variation mechanism into reference service proposal (Question 9)

Bringing the tariff variation mechanism into the reference service proposal may provide some certainty benefit so long as:

- The network service provider retains the opportunity, as under the current approach, to respond to an AER draft decision on the tariff variation mechanism; and
- The AER is bound by the final decision at the reference service proposal stage—any rules should ensure the regulator is not incentivised to game the process and create uncertainty on how demand risk is shared.

### 5.3 Additional rule guidance on tariffs (Question 10)

It is not clear the current rules have prevented the AER from being able to seek changes to gas network service providers' tariffs. The AER has sought and achieved variations to JGN and Evoenergy tariff proposals in previous price review processes.

Any guidance on tariffs should be high level as each network service provider should have the flexibility in managing demand in their networks depending on the tariff variation mechanism determined, the respective network characteristics, impact on customers, and State policy requirements. It would not, for example, be appropriate for a price cap or similar (i.e. a hybrid form of control) to be imposed, but have overly restrictive tariff requirements that do not allow the service provider to manage the demand risk in the way they see fit. This would be counter to the intended incentive of a price cap.

Additionally, different state governments may adopt different policies that may consider the role of gas differently. States with large industrial footprint and gas penetration may have a different view from states and territories with low industrial demand and gas penetration.

Therefore, the rules should maintain sufficient flexibility in tariff structures.

### 5.4 AER flexibility to determine access arrangement length and to trigger variations (question 11)

As the AEMC recognises, NGR rule 50 already provides the AER discretion to provide an alternative length to that proposed by the service provider, where this is consistent with the NGO and revenue and pricing principles. It is not clear there is a need for AER discretion beyond consistency with the NGO to change the access arrangement length.

In terms of guidance within the rules, the AEMC could consider limiting the AER discretion to a set of criteria understood by all parties in advance. This could support certainty and limit investor concerns of instability or arbitrary discretion change. This may include criteria such as to align with expected significant policy announcements, such as taken in by the New Zealand Commerce Commission.<sup>59</sup> Given the current multi-year process of preparing, proposing and assessing access agreements, the AEMC could also consider a lower limit to the access arrangement length.

It is unclear what the benefits would be of aligning the timing of electricity and gas decisions in a relevant jurisdiction outside of dual-fuel service providers. In contrast, it may be more useful to have certainty in one decision prior to considering the other—for example by having a final demand forecast. Practically, electricity networks will detect electrification prior to gas networks as they will see demand increases prior to gas networks detecting demand reductions, not least due to the more frequent metering.

Additionally, alignment of regulatory periods may burden stakeholders (e.g. retailers, consumer groups) who must engage with both sectors simultaneously, risking engagement fatigue and diluted focus on gas issues, and may lead to higher administrative costs for the AER.

### 5.5 AER flexibility to trigger re-opener provisions (question 12)

The AEMC has asked whether both the service provider and the AER should have the ability to reopen the access arrangement if certain trigger events occur. While this may offer flexibility in some circumstances, it introduces significant risk for service providers—particularly if the AER exercises this power frequently or unpredictably.

Firstly, service providers typically hedge financial and operational risks over the duration of the access arrangement period. Reopening the arrangement mid-period undermines these hedging strategies and creates uncertainty around cost recovery.

Secondly, frequent reopening could erode the integrity of the incentive-based regulatory framework. If the AER reopens the arrangement in response to service providers outperforming benchmarks, it risks shifting the regime from an incentive-based model to a cost-of-service model, thereby penalising efficiency and innovation.

Given the heightened uncertainty in the gas sector, it is reasonable for network service providers to retain the ability to initiate a reopening where material changes occur. This has not led to many reopeners so there is little evidence to support constraining the network service provider's ability to trigger these. However, extending this right to the regulator risks destabilising the framework and undermining investment confidence.

### 5.6 Service provider existing and additional incentives (Question 13)

A number of gas network service providers, including JGN and those in Victoria, already have a service incentive scheme tied to their Capital Expenditure Sharing Scheme. The AER already has flexibility in approving schemes by requiring network service providers to propose service incentive schemes. For example, JGN has an Efficiency Carryover Mechanism for its operating expenditure. These mechanisms have incentivised networks to pursue efficient capital and operational expenditures across multiple price review periods.

The AEMC has identified some international examples of additional incentives to manage declining demand. While we consider it premature to be solving issues of fully depreciated regulated asset bases, we recognise that no commercial business will operate if their revenue is equal only to operating expenditure. Once the assets reach the end of their economic lives the rules could facilitate incentives for service providers to keep them in operation where this meets the long-term interests of customers.

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<sup>59</sup> NZ Commerce Commission, Final Reasons Paper, Default price-quality paths for gas pipeline businesses from 1 October 2022, 31 May 2022.

## 5.7 Could the proposed changes inefficiently incentivise pipeline elections? (Question 14)

Based on the current rule change proposal, it is unclear why a non-scheme pipeline operator would seek to become a scheme pipeline. Indeed, key aspects of some of the changes as proposed by ECA and JEC—particularly the introduction of provisions that could result in investors being deprived of a reasonable opportunity to recover at least their efficient costs—would be highly likely to act as a strong disincentive for any non-scheme pipeline to elect to become a scheme pipeline, relative to the incentives under the regulatory framework as it currently stands.

## 6. Assessment criteria

The assessment criteria should include greater emphasis and discussion on efficient utilisation.

This section covers Jemena's response to AEMC:

- Question 16: Assessment framework: 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?

The assessment criteria does not appear to suggest there will be sufficient consideration of efficient utilisation when considering the rule changes. The AEMC includes one sub-question on distorting efficient signals, within the outcomes for customers.

However, given the prominence of efficient utilisation within the NGO and revenue and pricing principles, the AEMC should have regard to the economic costs and risk of under or over-utilisation. There is legal precedent that makes clear the 'efficient costs' principle is fundamental to the achievement of the NGO.<sup>60</sup> Assessment should focus on whether rule change proposals will mean that gas network service providers' building block revenue is prevented from being set at efficient levels. And if they are, what this would mean for the resulting price signals and incentives to use the network.

Additionally, in section 4.3.1 of the consultation paper in relation to assessment criteria outcomes for customers, the AEMC ask "*Would the solution be consistent with the AEMC's work on equity or energy consumers, particularly if present customers are being asked to shoulder a proportionally greater cost burden than future customers?*".

Accelerated depreciation in itself does not necessarily mean a greater proportion of cost is being borne by current customers than future customers. It may, in fact, be the opposite in that accelerating depreciation is levelling the burden from one that is currently over-burdening a smaller number of future customers.

The AEMC intent may be that accelerating depreciation means a greater proportion of cost is borne by current customers *relative to the status quo*, and if so, the AEMC should clarify, noting that this does not in itself make comment on the appropriateness of the depreciation schedules. It remains important that discussion on depreciation schedules focuses on how these can be an appropriate tool used to promote efficiency, including via efficient price signals, and therefore support the NGO.

<sup>60</sup> See, for example: *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, at [787].