ENERGY CONSUMERS AUSTRALIA

Consultation paper

National Gas Rules Amendments:

Gas Networks in Transition

Energy Consumer Australia's submission to the Australian Energy Market Commission

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Contents

Energy Consumers Australia is the national voice for household and small business energy consumers. We advocate for a fair, affordable, and reliable energy system that meets everyone's needs and leaves no one behind on the journey to net zero.

Part A: Introduction

Energy Consumers Australia (ECA) welcomes the opportunity to comment on the *Gas Networks in Transition* consultation paper for the rule change requests proposed by ECA and the Justice Equity Centre (JEC).

This submission sets out ECA's position on the issues raised in the consultation paper and explains why the proposed package of reforms is needed to protect consumers through the transition of gas networks. Our rule changes are no-regrets, sensible changes that should be made to improve the regulation of gas networks in decline. We continue to advocate for these changes through this consultation process but recognise that these are not the only changes that are needed. We welcome the Commission's holistic approach in the consultation paper, which considers a broader range of issues and possible reforms that are needed to promote the long-term interests of consumers as gas networks transition.

As one of the proponents of the rule change requests under consultation, the main purpose of this submission is not to restate those proposals but to respond to the questions raised by the Commission and highlight the key issues that must be addressed to ensure a fair, efficient and well-managed transition for consumers.

The framework must evolve to manage network decline fairly and efficiently for Australian households and small businesses

The gas transition is no longer hypothetical. Demand for residential and small-business gas is falling, yet networks continue to invest and recover costs as though growth will return. Without clear direction, the transition risks becoming disorderly and unfair, leaving households to absorb the cost of a system that is already shrinking. The Commission's review is an opportunity to replace uncertainty with structure and ensure consumers are protected from avoidable harm.

1. The regulatory framework was built for expansion, not decline

The National Gas Rules were designed for a growing network and still assume ongoing growth in connections, asset growth and long-lived investment. This no longer reflects reality. Residential and commercial gas use is falling, but expenditure and planning remain tied to historic assumptions of growth. The result is rising consumer costs and growing stranded-asset risk. Clearer rules are needed to treat consumers fairly, guide efficient investment and ensure capital recovery reflects a declining, rather than expanding, market. Our proposed rule change to capex criteria aims to provide greater certainty and consistency to avoid unnecessary capital spending.

2. Inefficiency and inequity are compounding as demand declines

The decline of household and small-business gas use is certain. What remains uncertain is how quickly demand will fall, how costs will be shared, and when parts of the network will close. The current framework does not deal effectively with this uncertainty. It allows networks to plan and invest as if demand will recover, locking in inefficient capital spending and shifting risks to consumers.

The framework cannot remove uncertainty, but it can ensure consumers are treated fairly within it. Rules should require networks to justify investment and cost recovery decisions in light of clear evidence about demand decline, and to show how risks and costs are being shared equitably between investors and consumers. Without this, inefficiency will persist, and those least able to electrify, such as renters, small businesses and low-income households, will continue to bear a disproportionate share of the costs.

3. Planning and transparency are essential to avoid a disorderly decline

Unlike electricity, gas distribution has no mandated public planning process. This lack of transparency makes it more difficult for governments, regulators and communities to coordinate electrification and electricity network infrastructure upgrades. Poor planning leads to poor decisions, increasing costs for consumers. Clear planning would allow earlier action, better coordination with electricity networks, and an orderly, least-cost transition. Our proposed gas planning requirements rule change would require gas networks to plan for the future of their networks and make this information readily available for all stakeholders.

4. Cost recovery rules must protect consumers from stranded-asset risk

Current rules allow networks to accelerate depreciation to address stranded asset risk, shifting transition-related costs to consumers while continuing to invest as if demand were stable. Stronger safeguards are needed to ensure accelerated cost recovery only occurs where investors bear a fair share of this risk, consumers benefit overall, and the approach aligns with credible decommissioning and transition plans. Our rule change would make accelerated depreciation contingent on greater consumer protections, so that consumers are not left paying an unfair share of stranded assets.

5. Pricing and incentives must reflect the new reality

Existing incentive schemes and tariff structures were designed to encourage network growth. In a declining market, those same settings can produce perverse outcomes: rewarding expansion, discouraging decommissioning, and increasing costs for consumers who stay connected. Incentives must now focus on efficient downsizing, data transparency, and consumer support, rewarding networks for reducing long-term costs and coordinating with electricity distributors, not for sustaining throughput.

6. Clear policy direction is essential to give consumers confidence

The absence of clear direction on the future role of gas for households and small businesses, compared with industrial users, is creating uncertainty that affects every part of the energy system. Most jurisdictions have not set out whether residential and small-business gas use should continue or phase down, leaving regulators, networks and consumers without a shared basis for planning.

Clear jurisdictional policy is critical to give consumers confidence and to enable coordinated decisions by governments, regulators and industry. When jurisdictions provide a clear policy framework, it also sends a signal to the Commonwealth about where national action is needed, such as stronger appliance efficiency standards, product labelling and safety requirements. These complementary measures help protect consumers and manage risk across the transition.

With greater clarity, governments can target support where it is most needed, regulators can plan network upgrades more efficiently, and consumers can make informed decisions about their future energy use. A clear policy direction will give all parties the certainty required to manage the decline of gas use fairly and efficiently.

Consumers are already living through this transition. Every appliance purchase, every bill, every connection decision is shaped by how governments and regulators manage uncertainty. Gas use in homes and small businesses is in structural decline as consumers electrify to lower costs and emissions. Yet the regulatory framework remains designed for a system in growth. Without reform, consumers face the risk of a disorderly demand decline scenario, inefficient investment in assets that may never be fully used and widening inequities between those who can electrify and those who cannot.

ECA acknowledges the important work of the Commission in leading this review. While this consultation alone cannot resolve all the challenges of the gas transition, it is a critical step in aligning the regulatory framework with the realities of a shrinking system.

We thank the Commission for considering this submission. If you have any questions, please contact Claire Ohk at Claire.Ohk@energyconsumersaustralia.com.au

Yours sincerely,

Brendan French

Chief Executive Officer

Part B: Consultation Questions

The following sections respond to each of the consultation questions raised by the Commission, outlining ECA's position and recommendations for improvement.

Issues around the energy transition and scope of NGR changes

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

1. Do stakeholders agree that there is value in considering the additional NGR issues the Commission identified alongside the rule change requests?
2. Are there any other additional issues that should be considered within the NGR framework? If so, why?
3. Noting the AEMC's role is to consider and make changes to the energy rules, are there changes outside the NGR framework that are required to address the issues raised?

Australians are on a path to net zero by 2050. On this basis, governments, businesses and households have already made long-term investment decisions to support that goal. Billions of dollars are being directed toward electricity network upgrades, renewable generation, and consumer energy resources such as solar, batteries and heat pumps.[1] These investments reflect a clear direction of travel: an electrified low-emissions energy system.

At the same time, gas network investments are continuing. Large expansion projects are being approved even as residential and small business gas use declines. Consumers are, in effect, funding two very expensive energy systems – one that is being built for the future and another where its future is uncertain and gradually being used less by households.

Consumer behaviour is already shifting and responding to these external signals. Gas use in eastern Australia has fallen by around 30 per cent since its peak in 2012–13, and residential demand declined by about 6 per cent in FY2023–24 alone.[2] Our survey has shown that more than one-third of households connected to gas expect to cancel their gas supply within the next decade, and nearly one in ten intend to do so within two years.[3] This is not a question of whether gas still plays a role, but how the costs of maintaining that role are shared fairly as consumption patterns change.

Additionally, the pace of electrification will not be uniform. While some households are already switching away from gas, many others face significant barriers that make the transition slower or more complex. These are often people who cannot act unilaterally, such as renters, apartment residents and households in multi-dwelling buildings, or those for whom the upfront costs of rewiring and appliance replacement remain out of reach, even with modest subsidies. For these groups, the timing and affordability of electrification will depend heavily on coordinated planning, landlord participation, and targeted support, not just individual choice. Without reform, the cost of keeping the gas network operating will increasingly fall on these households. People who cannot yet afford to leave should not be left to carry the financial burden of a network in decline.

[1] See: AEMO, *Integrated System Plan 2024*, p. 13; CEFC, *Annual Report 2023–24*, p. 4; DCCEEW, *Built Environment Sector Plan 2025*, p. 19.
[2] IEEFA, 2024, *Slump in Eastern Australia Gas Demand Shows No Signs of Easing*; DCCEEW, 2025, *Australian Energy Update, p.9*.
[3] ECA, 2024, *Consumer Energy Report Card: How Households Use Gas and Attitudes Toward Electrification*.

Policy settings across jurisdictions remain inconsistent, reflecting fundamentally different views on the future role of gas in homes and small businesses.

At the Commonwealth level, the direction is increasingly clear but not yet definitive. The *Built Environment Sector Plan* identifies "electrification where possible" as a key priority for reducing emissions from buildings, noting that switching from gas to electricity for space and water heating represents the largest and most immediate opportunity to cut direct emissions and household energy costs. Similarly, the Future Gas Strategy recognises that replacing household gas appliances with efficient electric alternatives will substantially lower bills while cutting emissions, and that over time, gas use should shift to higher-value, non-substitutable applications such as industrial feedstocks and firming generation. It currently emphasises consumer choice and an orderly transition, leaving states and territories to set their own directions.

Victoria and the ACT have taken the lead with explicit phase-out timelines and bans on new gas connections. Other jurisdictions such as South Australia have continued to support a role for gas in households. This divergence means the pace of change will vary, but it also highlights that electrification policy in Australia is subject to inconsistent approaches by state and territory governments rather than there being a unified national approach. The result is ongoing uncertainty for consumers, distributors, and regulators about how the transition will unfold.

Within this context, the Commission's role is critical. It is essential that the national regulatory framework under the National Gas Law and Rules recognises and is capable of managing the expected decline of gas networks, delivering fair, efficient and predictable outcomes for households and small businesses regardless of what jurisdictional policy settings are in place. The Commission's role through this consultation is to ensure that the framework remains fit for purpose as gas demand falls by providing clear consistent and nationally coherent rule settings that can manage the decline fairly and efficiently, even as state and territory policy approaches diverge. This includes making necessary changes to the National Gas Rules that are within the Commission's remit, but the Commission should also use this opportunity to highlight and make recommendations in relation to broader policy and legislative settings where these are inhibiting fair outcomes for consumers as the gas network transitions.

An unmanaged demand decline risks a disorderly transition and higher costs for consumers

The combination of falling demand, fragmented policy settings, and ongoing capital investment creates a real risk of an unmanaged demand decline in gas networks. Without intervention, the system could enter a self-reinforcing cycle where prices rise as customers leave, driving further disconnections and increasing costs for those who remain.

Households and small businesses already provide around 90 per cent of gas distribution network revenue even though they account for a smaller share of total gas use.[4] As more consumers switch to electricity, fewer remain to pay for the largely fixed costs of the system. There is currently no clear national plan for how these costs will be recovered. Under existing arrangements, regulators must allow networks a reasonable opportunity to recover efficient costs, which means higher prices for those who stay connected.

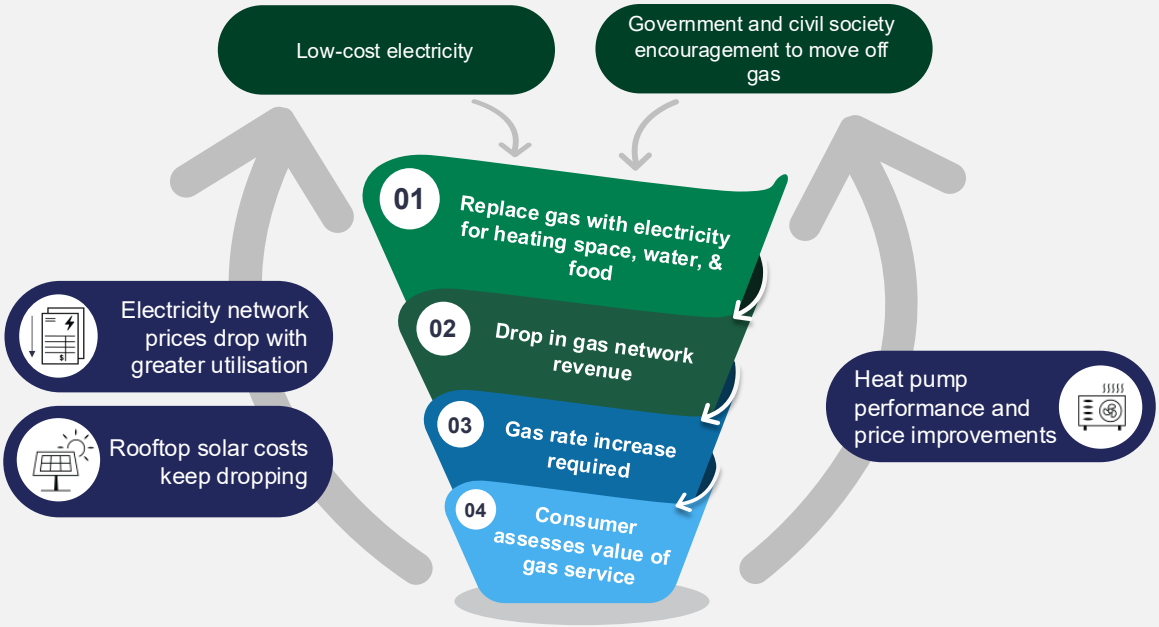
Independent modelling for ECA shows that, under current settings, network charges on household gas bills could more than quadruple by 2050, from roughly $280 per year today to about $1,170 per year.[5]

[4] AER, 2022 Gas Network Performance Report, Figure 7-9.
[5] ECA and Dynamic Analysis, Turning Down the Gas: Reducing consumer risk, commissioned by ECA, September 2024

International experience suggests the outcome could be even more pronounced.[6] Rising prices would in turn prompt more consumers to leave the system, deepening the cycle unless managed through coordinated planning and regulatory reform.

An unmanaged demand decline scenario, where the fixed costs of operating and maintaining the gas network are spread across a shrinking customer base, is demonstrated in the diagram below.

An unmanaged decline in gas could create a vicious cycle, with consumers with less agency being stuck paying unreasonable gas bills



This scenario creates inefficient investment risks for both networks and households, although the nature of these risks is fundamentally different.

For networks, investment is a commercial decision made to deliver regulated returns within the framework set by the Rules. Despite clear and longstanding signals of decline, gas distributors continue to propose major capital programs that reflect historic assumptions of stable or growing demand. While some expenditure is unavoidable to maintain safety and reliability, the overall investment settings have not yet evolved to reflect a shrinking customer base and the need to manage assets over a shorter economic life. Under the current framework, those transition-related costs and risks are being shifted to consumers through ongoing cost recovery for assets that may never be fully used. The NGR were written for an expanding market, not one in decline. They do not yet provide sufficient safeguards to ensure that investors, rather than consumers, bear the cost of their decisions.

For households, the situation is very different. A home is not an investment vehicle but the centre of daily life. Households make choices about appliances and connections based on comfort, affordability, and the information available to them. Without clear planning and consumer guidance, many may make decisions that later prove inefficient, such as installing new gas appliances or connecting to the network

[6] Jan Rosenow, et. al. 2024 "The elephant in the room: How do we regulate gas transportation infrastructure as gas demand declines?, One Earth, Volume 7, Issue 7, pp. 1158-1161

that become stranded long before the end of their expected life. These outcomes are not the result of poor judgment but of limited information and weak system planning.

An unmanaged decline is not inevitable. With stronger planning, transparency, and targeted support, governments and regulators can coordinate the transition to protect consumers, maintain safety, and deliver an orderly, least-cost wind-down of the network.

Declining demand also raises the risk of stranded assets. ECA's analysis indicates that, on current settings, one large network's regulated asset base (RAB) could still be around $2.3 billion by 2055.[7] Some distributors have responded by seeking accelerated depreciation to recover costs faster.[8] However, this raises bills today, shifts risk and costs to current consumers, and does little to change the long-term value of the regulated asset base unless combined with broader measures that reduce future investment and enable orderly downsizing.

Gas distributors continue to propose significant capital programs that reflect historic assumptions of demand growth rather than managed decline. The NGR are not yet equipped to require transparent planning for network rationalisation or robust consideration of non-network and decommissioning alternatives. Unlike electricity, gas networks have no mandated public planning process or annual planning report. This information gap makes it harder for regulators and stakeholders to test expenditure proposals and leaves households exposed to stranded investments in new gas appliances.

Energy regulation is complex, and consists of national and jurisdictional laws, national rules, jurisdictional regulations and regulatory guidelines. Multiple agencies are involved in administering and enforcing them. While ECA would welcome a holistic review of all of these components of regulation with a remit to actively shape the structural decline of the networks in consumers' best interests, we cannot initiate such a review. Thanks to the "open-source" nature of the rule change process, we have been able to propose these rule changes, and we appreciate the Commission's prioritisation of them. We consider these rule changes:

- represent an incremental improvement to the operation of the NGO, noting that we welcome the Commission's consideration of additional issues and potential remedies;
- are each justifiable on their own merits;
- work in concert with each other to help protect consumers from bearing additional risks from gas network decline;
- are necessary, but not sufficient to support more significant reforms, such as the introduction of a strategic decommissioning framework, that will further mitigate these risks, and;
- help create the context for constructive discussions on the broader reforms required.

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

Yes, we strongly agree there is value in the Commission considering the additional NGR issues identified alongside our rule change requests. The transition impacts many interconnected elements of the framework that need to be considered holistically. ECA's rule change requests are intended to address key consumer issues arising from the declining gas network but do not address all the issues, which require coordinated efforts from governments, gas networks and market bodies. The further issues identified by the Commission are critical to how risk and cost are shared.

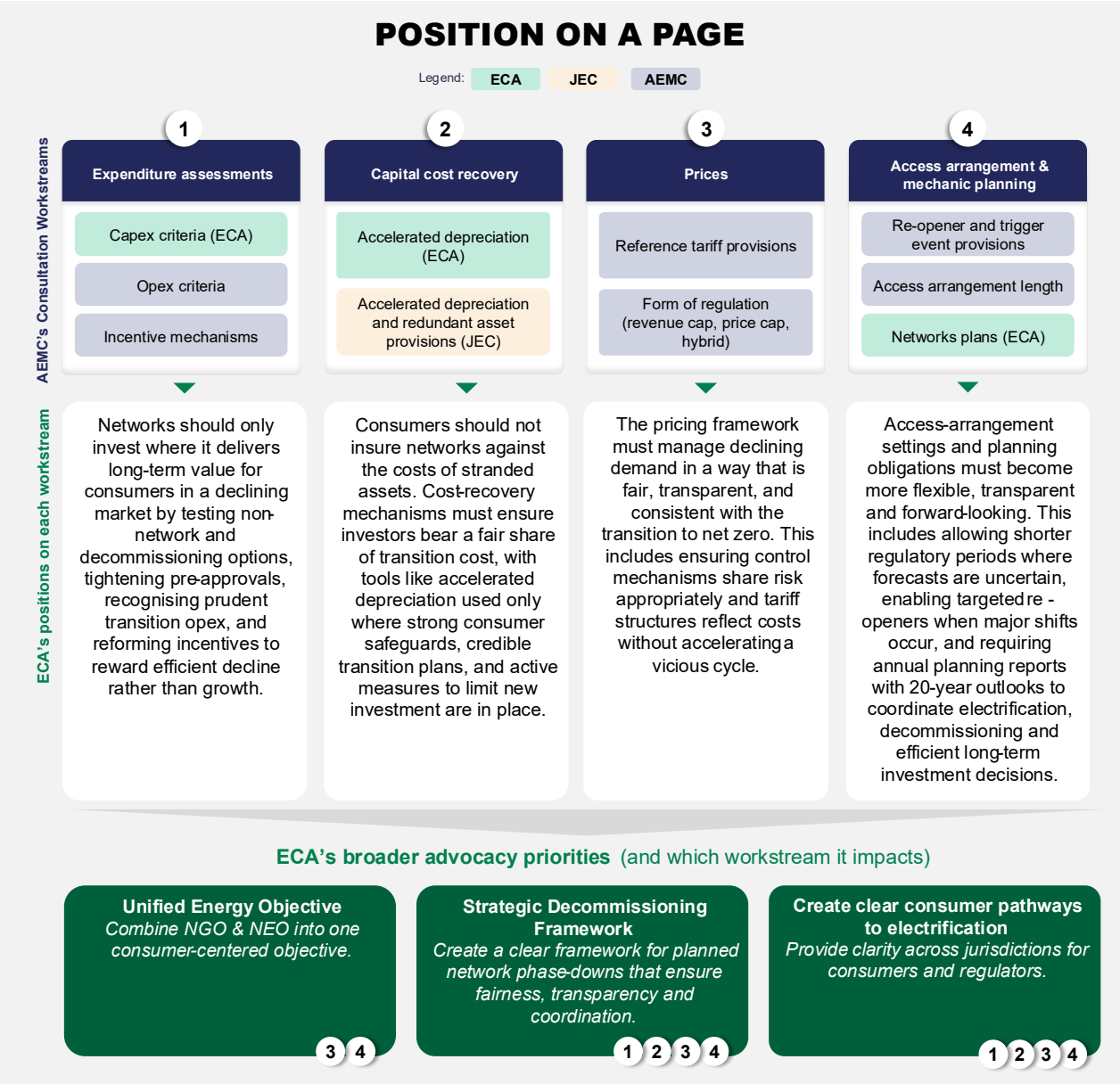
[7] ECA and Dynamic Analysis, Turning Down the Gas: Reducing consumer risk, commissioned by ECA, September 2024
[8] AER, November 2024, Draft Decision, Jemena gas network access arrangement 2025-30

The Commission's broader review provides an opportunity to align related parts of the regulatory framework, including expenditure assessment, capital cost recovery, pricing, and planning, with the reality of declining demand. ECA's proposed reforms cover connections, capital-expenditure criteria, depreciation, and gas planning. These reforms complement the Commission's broader workstreams and share a common goal of ensuring the framework supports fair outcomes for consumers as gas networks decline.

Without reform, consumers who remain on gas face rising bills, inefficient investment and inequitable outcomes. The risks of an unmanaged decline are not inevitable, but they require timely action from regulators, governments and industry to be avoided.

Figure 1 summarises ECA's positions across the workstreams where the Commission have highlighted the additional NGR issues alongside the issues raised in the rule change requests.

Figure 1 | ECA's position on a page



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

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

Some aspects of the gas transition extend beyond the scope of the National Gas Rules. The decline of the gas network cannot be managed by rule changes alone. It requires coordinated action from governments, regulators, industry and consumers. ECA encourages the Commission to use this process to highlight where broader reform may be required. For the avoidance of doubt, we do not consider that the need for broader reform to fully mitigate consumer risks and effectively manage the transition invalidates or undermines the case for any of these rule changes.

While the Commission's review focuses on targeted amendments to the Rules, those changes cannot on their own ensure a fair, efficient and orderly transition. The rule changes ECA has proposed are designed to make the current framework more fit for purpose – by tightening expenditure tests, ensuring fair cost recovery and requiring forward planning. But for these reforms to be most effective, they must operate within a broader policy and governance framework that gives clear direction on the future role of gas, ensures consistency across energy markets, and provides a structured pathway managing the network's physical downsizing.

The consultation paper notes that, "Other solutions outside the NGR, including governmental policies, changes to the national gas law, etc. may be necessary to comprehensively address the impacts of uncertain gas demand."[9] The Commission notes these are decisions outside its remit but that it will closely engage with jurisdictions through the consultation process. We encourage the Commission to also consider making recommendations to jurisdictions where necessary reforms are outside its remit, as it has done in other recent rule change processes.[10]

The three broader reforms to the policy, regulatory and planning architecture outlined below would lay the groundwork for an orderly phase-down of gas networks and a least-cost transition to electrification. They will not, on their own, deliver the full transformation required, but together they provide the foundations for a fair and coordinated transition: the first establishes a common consumer-centred objective across energy markets; the second provides a structured framework for safely and fairly retiring parts of the gas network; and the third ensures that jurisdictions set clear policy direction so these processes occur within an agreed national context.

1. **Combine the National Gas Objective (NGO) and National Electricity Objective (NEO)** into a single, consumer-centred energy objective to ensure fair treatment of consumers across markets.

The NGO requires the Commission to promote the long-term interests of gas consumers but treats these interests separately from the interests of electricity consumers. This approach does not explicitly recognise that households and small businesses rely on both electricity and gas to meet the same everyday energy needs. In practice, consumers who use both electricity and gas experience energy as a single essential service. Maintaining separate objectives for gas and electricity embeds siloed regulation of what, for consumers, is one integrated energy system providing reliable, affordable and safe energy services for heating, cooling, cooking and other daily uses.

[9] AEMC, 2025, *Gas Networks in Transition*, Consultation paper, p.v, available at: Consultation paper - GRC0082 - Gas networks in transition
[10] E.g. AEMC, 2025, Final determination on Improving the application of concessions to bills.

As the Grattan Institute notes:

"[T]he National Gas Law and the National Electricity Law treat gas consumers as entirely separately to electricity consumers. But every gas consumer is also an electricity consumer, and decisions made by and about gas consumers have ramifications for electricity consumers. There should be a single legal framework for energy, with the consumers at the centre."[11]

Combining the NGO and NEO would better reflect that decisions impacting gas consumers also impact electricity consumers, and would support consistent, whole-of-system planning and regulation through the transition. It would also give regulators a single, coherent test for what serves the long-term interests of energy consumers, allowing the Commission and AER to assess trade-offs across fuels rather than within siloes.

In the short term, the Commission and the AER should interpret the NGO broadly, recognising that gas consumers are also electricity consumers. This alignment would also support closer coordination between gas and electricity planning processes and allow for shorter, more responsive regulatory review cycles benefitting consumers.

We would welcome the Commission to explore further how a unified consumer-centred objective can simplify decision-making, improve accountability, and ensure alignment across markets as energy systems evolve. We recognise that this would require changes to the National Gas Law and National Electricity Law that are outside the Commission's remit. However, the Commission could use this review process to make recommendations to government where broader changes are required to support the transition.

2. **Establish a framework for strategic decommissioning** so networks can safely and fairly withdraw from areas where gas use has declined.

We acknowledge the Commission's statement that, 'the decommissioning of gas assets may need to be subject to a specific planning assessment and consultation framework (and not just additional information requirements on gas distributors)'.[12] We support the need for such a framework to be developed, potentially through further changes to the National Gas Rules.

A clear decommissioning framework is essential to managing an orderly, least-cost wind-down of gas networks. It would require networks to test decommissioning options against like-for-like replacement projects, provide a policy basis for redundancy decisions and conditional accelerated depreciation, and guide fair treatment of abolishment fees and exit costs so consumers are not trapped on gas. It would also make annual planning, and local area plans the vehicles for sequencing network withdrawals and coordinating upgrades to electricity infrastructure.

Importantly, a strategic decommissioning framework is needed to enable further consideration of jurisdictional 'obligation to supply' arrangements. As gas use declines, there may be circumstances where continuing to serve one or two remaining customers is no longer efficient or fair to others. This raises the question of whether, and under what conditions, the obligation to supply gas should be varied or removed. Any change to that obligation must be made within a clear framework that ensures affected consumers have access to safe, affordable alternatives and are adequately supported through the transition.

[11] Grattan Institute, 2023,Getting off gas: why, how, and who should pay?, p.50.
[12] AEMC, Consultation paper - GRC0082 - Gas networks in transition, 30.

The Solstice Energy withdrawal in regional Victoria, where 10 regional towns will no longer have access to gas, provides a concrete illustration of the costs and risks when no such framework exists.[13] Many customers are faced with large costs with one resident estimated $28,000 to convert to full electric. Without a structured decommissioning process, affected households and businesses face abrupt transition, uncertainty about fairness of exist costs, and limited visibility into alternative pathways. This example underlines why a framework is needed so that communities are not left facing sudden asset retirements without recourse or support.

We therefore support the Commission in highlighting the need for a formal decommissioning framework and recommend that this review begin laying the groundwork for it. Later in this submission, we outline the key matters that such a framework would need to cover, including project scale and triggers, consultation processes, notice periods, consumer support, network incentives and the treatment of residual costs.

3. **Clear jurisdictional policy is needed on household and small-business gas use** to guide clear consumer pathways to electrification.

ECA welcomes the Commission's decision to use this review not only to consider specific rule changes but to explore the broader question of how the gas regulatory framework can support an orderly, consumer-centred transition. The Commission's approach rightly recognises that, without coordinated and transparent planning, Australia risks a disorderly demand decline where households and small businesses bear the costs of under-used or stranded assets. Such an outcome is not inevitable. With clear jurisdictional policy settings and consistent regulatory signals, the transition can be managed efficiently and fairly.

As outlined earlier in this submission, policies shaping households and small business gas use are currently led at the state level and differ across jurisdictions. Some jurisdictions are advancing clear electrification strategies and setting timelines for transition, while others remain technology-neutral or have yet to articulate their long-term position. This lack of clarity makes it difficult for regulators, networks and consumers to plan with confidence. It also risks conflating household and small-business gas users with industrial users, despite their very different pathways and options. For example, while renewable hydrogen may have a role in industrial applications, it is unlikely to be an efficient or practical substitute for household and small-business gas use. ECA supports consumers having genuine choice over how they heat, cook and power their homes and businesses. However, for choice to be meaningful, consumers need access to clear information, fair and transparent pricing, and market settings that do not disadvantage those who wish to switch or who cannot yet do so, including clear signals about the full and future costs of staying connected to or newly connecting to gas as demand declines. Clearer jurisdictional direction on the role of gas in the household and small-business sectors would give consumers the confidence to make informed decisions and allow governments to target support to those who need it most. It would also send clearer signals to the Commonwealth about where national action, such as stronger appliance efficiency standards, labelling and safety regulations, or coordinated consumer-protection measures, is required to support a fair and efficient transition.

While the Commission cannot set national gas policy, it plays a key role in identifying where divergent or ambiguous policy settings create regulatory uncertainty and expose consumers to unnecessary cost and risk. Through this review, the Commission could highlight the importance of clearer jurisdictional direction on household and small business gas use, distinct from industrial demand, and the need for consistent signals to guide efficient planning and investment.

[13] ABC, 2025, Solstice Energy to cut gas supply to 10 regional Victorian towns - ABC News

Figure 1 also identifies how our broader advocacy priorities align with Commission's major workstreams.

Workstream 1: Expenditure assessments

Question 2. What changes, if any, should be made to the NGR capital expenditure criteria?

1. Are changes required to the current capital expenditure criteria to better account for uncertainty in future gas demand? If so, would ECA's proposed amendments better account for uncertain demand outlooks than the current criteria?
2. What do you consider would be the benefits and costs of ECA's proposed approach (for consumers, service providers and the regulator)?
3. Are there any alternative, preferable solutions to address the issues identified by ECA with the current capital expenditure criteria?
4. Do you consider changes are required to the rules in relation to advance determinations on capital expenditure in the context of the energy transition (rule 82)? If so, what are your views on the changes proposed by ECA (removing the provision or requiring the regulator to undertake consultation on proposals for advance determinations)?
5. Do you consider that additional types of expenditure may need to be recognised as capital expenditure in the context of the energy transition (e.g. decommissioning expenditure)?

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

Yes. ECA considers that changes to the current capital expenditure (capex) framework are required to ensure investment decisions by gas distribution networks properly account for the impacts of declining demand and stranded asset cost. It currently allows networks too much discretion in presenting business cases and does not require explicit assessment of declining demand, non-network alternatives, or future cost recovery risks. In practice, gas distributors continue to propose large discretionary capital programs, often at similar levels to past periods, while simultaneously claiming that stranded-asset risk justifies accelerated depreciation.

Our proposed rule changes relating to the capital expenditure criteria is provided on Section 5.3 (pages 19-20) of our rule change request.

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

ECA's detailed assessment is provided in Section 5.6 (page 21) of our rule change request.

In summary, gas distribution networks may incur some minor incremental costs as they prepare more robust justifications for their capex proposals and properly consider non-pipeline and other alternative options. However, the benefits are significant. Given that capex is currently running at c. $650m pa across the regulated gas distribution networks, even a one per cent benefit in lower capex would exceed any plausible estimate of costs.

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

As discussed in Section 5.2 (pages 18-19) of our rule change request, such as a more rigorous application of the existing criteria, particularly the requirement that a prudent service provider act efficiently, could in principle result in more constrained spending.

However, ECA considers that this is not sufficient to address the issue. The current test for when capex is "justifiable" does not explicitly require consideration of declining demand or consider demand management.

Therefore, our view is that more prescriptive rules will be most effective at ensuring efficient capital spending reducing unnecessary consumer costs and will require consideration of the relevant factors to be included as part of the proposed rule change.

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

Yes, Rule 80 is no longer fit for purpose in a declining-demand environment and should be repealed or substantially amended. The rule was originally introduced to provide investment certainty in a period of network growth, allowing the AER to *pre-approve* capital expenditure between access arrangement resets. In today's context of structural decline, policy change, and electrification, this approach exposes consumers to unnecessary risk and undermines flexibility in regulatory decision-making.

A binding pre-approval of capital expenditure, without mandatory consultation, can result in consumers paying for assets that later become under-utilised or redundant. Rule 80(1) makes an AER determination binding if the expenditure is delivered as proposed, meaning even significant policy or demand shifts cannot trigger reassessment. This locks consumers into outdated investment decisions and effectively guarantees revenue certainty for networks while consumers bear the downside if demand falls or government policy changes. That outcome is inconsistent with the National Gas Law, which entitles service providers only to a reasonable opportunity to recover efficient costs, not a guarantee of full cost recovery or protection from commercial risk. In an era of net zero, guaranteeing returns to infrastructure designed to transport a greenhouse gas no longer makes sense.

Lack of transparency also weakens accountability. Rule 80(2) makes public consultation optional. This removes an important safeguard and limits the ability of consumers and stakeholders to test whether a project represents efficient investment in a declining market.

Advance approvals discourage lower-cost or non-network alternatives. By giving networks confidence that capital expenditure will be rolled into the regulated asset base, Rule 80 reinforces a capital-heavy bias and weakens incentives to explore operational or strategic decommissioning options. This is contrary to the need for an efficient, orderly transition and fair cost allocation for consumers.

Rule 80 effectively guarantees revenue certainty for networks while consumers bear the downside if demand falls or policy changes. This appears to contradict other core elements of the NGL which entitles service providers to a reasonable opportunity to recover efficient costs – not a guarantee of full recovery or protection from commercial risk. Consumers should not be treated as the insurer of the network's investment decisions.

We therefore recommend that Rule 80 be deleted. If the Commission decides to retain it, the rule should be narrowed and amended to require:

- Mandatory public consultation before any advance determination is made
- A clear material-change test, allowing the AER to revisit or void determinations if policy, demand or technology assumptions materially shift; and
- Explicit consideration of non-network or decommissioning alternatives before granting approval.

In short, Rule 80 provides the wrong kind of certainty for a market in transition. True investment confidence will come from transparent, consultative, and adaptive processes that align with the realities of declining gas demand, not from pre-committing consumers to yesterday's investment decisions.

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

ECA agrees that the regulatory framework should clearly support and incentivise efficient decommissioning as part of managing network decline. Where safely retiring parts of the network is the lowest-cost option for consumers, it should be clearly in the network's commercial interest to pursue it.

Currently, decommissioning is treated inconsistently across networks and is often classified as operating expenditure, even when it provides enduring benefits comparable to capital investment (such as avoiding future maintenance and safety costs). The AER's Review of Incentive Schemes for Gas Networks focused on electricity incentive schemes (EBSS, CESS and STPIS) and did not recommend developing or applying additional schemes for gas networks. As a result, there remains limited regulatory guidance and no targeted incentive mechanism to support efficient, consumer-beneficial decommissioning in gas.[14] Similarly, Victoria's Gas Substitution Roadmap highlights decommissioning as a necessary component of an orderly phase-down of the network.[15] These findings underline that the issue is not just about classification, but about providing clear, consistent signals for efficient transition-related investment.

Both capex and opex are recoverable under the existing framework. Whether decommissioning is treated as capex or opex is secondary to ensuring that it is recoverable where it delivers long-term consumer benefits. In some cases, treating decommissioning as capex may be appropriate, particularly where the activity is directly linked to an asset's lifecycle and avoids future maintenance or safety costs. A reasonable investor would likely consider decommissioning costs as part of the total life-cycle cost of an asset, which supports the case for recognising it as recoverable expenditure. However, recovery could also occur through opex allowances or other mechanisms that explicitly recognise the value of least-cost outcomes.

To ensure decommissioning expenditure (whether capex or opex) is in consumers' long-term interests, its treatment should be guided by clear principles. These could include that:

- Efficiency – recovery should only be permitted where decommissioning demonstrably minimises total system costs compared to continued operation or replacement.

[14] AER, 2023, Final decision – Review of incentive schemes for networks, available at: https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf
[15] Victorian Government, 2022, Victoria's Gas Substitution Roadmap, available at: Victoria's Gas Substitution Roadmap

- Transparency – proposed decommissioning expenditure should be subject to open consultation and clear public reporting of assumptions, cost estimates and consumer impacts.
- Fairness – cost allocation should reflect who benefits and who bears the risk, ensuring that households are not left paying for redundant assets or transition costs that primarily benefit investors.
- Accountability – the regulator should have discretion to test and approve decommissioning proposals against these principles, with clear evidence that consumers are better off than under alternative options.

What matters is not the accounting treatment itself but that the framework creates strong incentives for networks to act when decommissioning is more efficient than replacement or continued operation, while ensuring costs are shared fairly and transparently.

Question 3. Are any changes required for operating expenditure?

1. Do you consider the current definition of operating expenditure (which includes expenditure for increasing long-term demand for pipeline services) is fit for purpose in the context of the energy transition?
2. Do you consider there are additional types of operating expenditure that may need to be recognised in the context of the energy transition?
3. Do you consider the regulatory framework appropriately balances the incentives between capital intensive solutions and asset management/maintenance solutions so that service providers have incentives to consider the most efficient options to address network needs? If not, what changes would be required to balance these incentives?

Are any changes required for operating expenditure?

Yes. The current framework does not adequately recognise the types of expenditure required to manage gas networks efficiently in an environment of structural decline. Operating expenditure (opex) plays a critical role in maintaining safety and reliability while enabling networks to adapt to falling demand. However, the Rules were written for a period of network expansion, where most expenditure was capital intensive and focused on growth.

As a result, transition-related activities, such as decommissioning, consumer coordination, and network planning, receive limited regulatory recognition, while the framework continues to favour capital expenditure that expands or sustains the asset base. This imbalance risks higher long-term costs for consumers and undermines incentives to pursue lower-cost operational or non-network solutions.

Reforms should make clear that opex which supports the safe, efficient, and equitable management of network decline is both prudent and recoverable. This would help shift the regulatory focus from asset growth to efficient decline and long-term consumer value.

1. Do you consider the current definition of operating expenditure (which includes expenditure for increasing long-term demand for pipeline services) is fit for purpose in the context of the energy transition?

No. As we have indicated in our rule change request (p 18) the current definition of operating expenditure is not fit for purpose in the context of the energy transition. Rule 69 currently includes a non-exhaustive limb that counts as opex that permits “expenditure incurred in increasing long-term demand for pipeline services.” This clause reflects a growth-era assumption that expanding gas use is inherently

efficient. It is now outdated and inconsistent with government policy directions and consumer expectations.

ECA recommends deleting this limb from the definition of opex to ensure the framework reflects the realities of transition and focuses expenditure on maintaining safety, reliability, and orderly withdrawal rather than demand growth.

2. Do you consider there are additional types of operating expenditure that may need to be recognised in the context of the energy transition?

Yes, the framework should explicitly recognise certain types of opex for managing decline and ensure that networks choose opex or non-network solutions. The goal is to remove any bias toward capital investment and ensure expenditure reflects the lowest-cost outcome for consumers.

The current framework creates an asymmetry: capex is defined, justified and recoverable through the Regulated Asset Base (RAB), while opex is defined broadly but not clearly linked to transition activities. As a result, distributors default to capex solutions (for example, mains replacement) even where opex solutions such as targeted maintenance, temporary remediation, or strategic decommissioning would be cheaper and better aligned with the NGO. As noted in our response to Question 2E, decommissioning activities may be more appropriately treated as capex or opex depending on their nature and consumer benefit. What matters is that such costs are recoverable when they demonstrably deliver long-term value to consumers.

These could include:

- Transition-related opex: activities such as annual network planning, demand-forecasting, and coordination with electricity networks and local governments.
- Decommissioning-related opex: make-safe and isolation works, site remediation, and customer communication required when parts of the network are retired rather than replaced.
- Consumer-coordination opex: engagement programs to help households and small businesses electrify safely and efficiently.
- Maintenance opex: targeted safety and asset management programs to keep essential services reliable as utilisation falls.

3. Do you consider the regulatory framework appropriately balances the incentives between capital intensive solutions and asset management/maintenance solutions so that service providers have incentives to consider the most efficient options to address network needs? If not, what changes would be required to balance these incentives?

No. The current framework continues to favour capital expenditure because networks earn a return on their regulated asset base, while equivalent operating or non-network solutions receive no comparable incentive. This structural bias encourages networks to propose replacement or augmentation projects even when targeted maintenance, operational adjustments, or strategic decommissioning would be more efficient.

The regulatory framework should require distributors to demonstrate they have seriously considered opex alternatives to capex. This includes evaluating strategic decommissioning against large replacement programs, or demand-side measures against augmentation. Regulators should be empowered to test whether the lowest-cost pathway for consumers has been selected, regardless of whether that expenditure is capital or operating in nature.

Given the Commission is open to widening the scope of the rule changes, we observe that, while our rule change proposals have utilised the conventional delineation of capex and opex, the conditions of declining networks and the imperative of minimising overall expenditure may merit consideration of alternative cost methodologies. Given the general perception that regulated networks exhibit a capital bias, then to the extent this is driven by a preference for growing the RAB, one potential solution is to adopt a total expenditure or "totex" framework. This does not distinguish between capex and opex but addresses intergenerational equity by allowing a proportion of totex to be recovered immediately and the remainder to be added to the RAB. Historical trends of capex and opex could be used to determine a reasonable allocation ratio. Specifically, this would help avoid the risks of:

- Networks being disincentivised from strategic decommissioning on the basis that decommissioning costs (including communications, planning, contribution to customer electrification etc) would technically need to be treated as opex given that these costs have no enduring benefit to the network versus carrying out a replacement project that could be added to the RAB
- As the transition progresses, networks may switch to seeking to minimise RAB additions that risk becoming stranded and favour opex to an inefficient degree.

We recognise a totex framework may require significant changes to the rules which currently refer specifically to capex and opex. ECA does not definitively favour a totex model, but we would welcome further analysis of its potential benefits in the context of this review to determine whether it could support more efficient and equitable outcomes for consumers. It would nonetheless be worth considering the potential benefits of such an approach.

Workstream 2: Capital cost recovery

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?

1. Do you agree with ECA and JEC that the current rules do not provide for appropriate consideration and management of assets at risk of becoming increasingly underutilised in the context of the energy transition, including consideration of how risk and costs are allocated between network service providers and consumers (including present and future consumers)?
2. Are there alternative solutions to those proposed in the ECA and JEC's rule change requests that would more effectively address cost recovery risks for efficient past and future investments

No. The current framework does not effectively manage or allocate transition-related risk and costs between consumers and service providers. While the NGL entitles distributors to a reasonable opportunity to recover efficient costs, it does not guarantee that networks recover their costs. In the context of the energy transition, it should not be assumed that all network costs will continue to be recovered from consumers. There needs to be a more equitable sharing of costs between networks, governments and consumers.

As provided in more detail in Section 5.1 (pages 15-18) of our rule change proposal, the existing rules have been applied in ways that protect networks from downside risk while exposing consumers to the cost of declining demand. Networks have maintained historic levels of capex and then sought accelerated depreciation to recover sunk costs earlier, effectively transferring stranded asset costs to current consumers. Regulators have generally prioritised short-term price stability through price-pathing rather than addressing who is best placed to manage the risk of assets that may no longer be needed.

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

Yes. Both the current rules and its application lack a coherent framework for managing under-utilised or redundant assets. There are no clear principles for when assets should be written down, who should bear the cost of stranding, or how decisions should balance fairness between current and future consumers in respect of that portion of the costs and risks that consumers bear. Rule 85 (redundancy provisions) allows the regulator to exclude redundant assets from the RAB, but it is silent on how or when this discretion should be exercised.

Meanwhile, networks have relied on Rule 89 (depreciation criteria) to justify accelerated depreciation, recovering more of the RAB upfront while still retaining upside if demand does not fall as forecast. This asymmetry means consumers pay more now but remain exposed later if the network becomes uneconomic, while investors face little or no downside despite long-standing awareness of transition risks. The result is an unbalanced and opaque risk-sharing model that neither protects consumers nor creates clear incentives for networks to plan and manage decline efficiently.

Question 5. How does ECA's proposal impact the recovery of capital costs for new and existing assets?

1. Do you consider changes are required to the depreciation provisions in the context of the uncertain outlook for gas demand (in terms of limiting variations to the rate of cost recovery and changes to asset lives)?
2. What do you consider would be the benefits and costs of ECA's proposed approach to restrict the use of accelerated depreciation through variations to the rate of cost recovery and changes to asset lives (for consumers, service providers and the regulator)?
3. What are your views on ECA's alternative solution of prohibiting the regulator from varying the depreciation rates for existing assets?

Our accelerated depreciation proposal, outlined in Section 5.3 (pages 19-20) of our rule change request, seeks to ensure that capital cost recovery in a declining market is fair, transparent and consistent with broader policy objectives. The proposal makes accelerated depreciation contingent on criteria that aim to ensure fairer cost sharing, and that align with broader jurisdictional policy settings.

The rule change does not seek to fully determine how transition costs are shared, as that broader allocation requires coordinated policy responses from governments. Instead, the rule change explicitly links accelerated depreciation decisions to jurisdictional policy settings by requiring that adjustments to asset lives may only occur when certain conditions are met. For example, new subrule 3 would set out the conditions under which an adjustment in asset lives (as described in subrule 1c) may be allowed, including where the relevant legislation or regulations of a participating jurisdiction support strategic decommissioning and electrification.

Clearer constraints on when accelerated depreciation applies also signal to gas distribution networks that they should evaluate stranding risk on all new expenditure and better orient their capital programs to a declining customer base. It only allows consumers to pay for accelerated depreciation when network investors have demonstrated that they are bearing a reasonable share of the crystallised investment risk; as investors in any other declining business would expect to do.

1. Do you consider changes are required to the depreciation provisions in the context of the uncertain outlook for gas demand (in terms of limiting variations to the rate of cost recovery and changes to asset lives)?

Yes. ECA consider that changes to the depreciation provisions are required to ensure cost recovery is fair and transparent. The current provisions allow accelerated cost recovery without clear principles for how stranded-asset risks are shared, which in practice has shifted costs onto consumers.

As detailed in Section 5.3 (page 19) of our rule change request, we propose an amendment to subrule 1c) to limit changes in asset lives to circumstances where the relevant conditions have been met (as set out in subrule 3). The new subrule 3 would require that adjustments to asset lives are only allowed where relevant jurisdictional legislation or regulation supports strategic decommissioning and electrification, and where networks can demonstrate consistency between their depreciation approach and their forward capital expenditure forecasts.

ECA's analysis, based on modelling of the Jemena Gas Network, shows that accelerated depreciation on its own delivers only a small reduction in the RAB by mid-century, while increasing near-term bills. This leaves consumers paying more today without meaningfully reducing the underlying cost of stranding. While this analysis was specific to Jemena's gas network, the findings have broader applicability across other gas networks.

The rule should therefore be amended so that any variation to depreciation schedules or asset lives is conditional, transparent and demonstrably in consumers' long-term interests.

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

Consumers: The proposal reduces exposure to risks that consumers are not well placed to manage. It aligns depreciation with clear conditions such as no consumer-funded new connections, credible planning and decommissioning arrangements, and investor risk sharing. The likely result is more disciplined investment, fewer discretionary additions to the asset base, and lower prices than under unconditional accelerated depreciation.

ECA-commissioned Dynamic Analysis modelling shows Jemena's proposed acceleration would add about $130 to a typical customer's bill over 2026–30 yet only reduce the RAB by ~10% by 2055 (from $2.3b to $2.1b), which does little at all to protect customers from stranding consequences. Accordingly, ECA's proposal notes that, other things equal, tightening depreciation access "will likely drive less overall discretionary expenditure… [and] constrain if not reduce network prices."[16]

Service providers: The proposal provides clearer expectations and a more transparent framework for the use of accelerated depreciation. Networks would retain access to this tool, but only when they demonstrate actions consistent with managing a declining network.

These actions include conservative life assumptions, genuine consideration of non-network and decommissioning options, and a commensurate investor contribution through write-downs. This improves incentives to re-shape capex and asset management to match shrinking demand.

[16] ECA and Dynamic Analysis, Turning Down the Gas: Reducing consumer risk, commissioned by ECA, September 2024

Noting that stranded-asset risk is not considered a systemic financial risk, there is no reason to suppose that gas distribution networks' cost of capital would be materially affected, especially as accelerated depreciation remains available when the relevant conditions are met.

Regulator: The regulator would have clearer rules to apply. This would close the current gap where the regulator can decide how much acceleration to allow but does not have rules that require it to also check whether consumers are being protected through other safeguards.

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

This prohibition would remove a blunt tool that has, in practice, been used in ways that expose consumers to greater costs. It would also be straightforward to apply. However, it may be too rigid because it takes away a mechanism that, in some limited cases, can help manage the financial stability of networks and smooth consumer price impacts. For that reason, ECA has not proposed a blanket ban on accelerated depreciation. Instead, we have proposed conditional accelerated depreciation, with strict consumer protection requirements to be contained in the Rules. We think this proposal is a more proportionate and targeted approach to the problem.

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

1. Do you consider changes are required to the capital redundancy provisions in the context of the energy transition and an uncertain gas demand outlook? If so, what amendments do you consider are necessary?
2. Do you consider the definition of redundant assets should be amended as proposed by JEC to include: a. assets that are economically inefficient to use? b. anticipated redundant assets?
3. Do you agree with JEC's proposal that service providers and the regulator should use accelerated depreciation in conjunction with the redundant asset provisions only if used to address capital cost recovery risks or redundancy?
4. What do you consider would be the benefits and costs (for consumers, service providers and the regulator) of JEC's proposed approach to:
    a. defining and assessing asset redundancy, and
    b. allowing for accelerated depreciation to address capital cost recovery risks only in conjunction with the redundant asset provisions?
5. What are your views on JEC's alternative solution to outright prohibit the use of accelerated depreciation?

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

The current framework does not effectively deal with recovery of capital costs as demand declines. The existing rules were designed for networks that were stable or growing, not in structural contraction. Without reform, consumers risk paying twice. They could pay once to sustain under-used gas assets and again to fund the electricity infrastructure needed for electrification.

Under today's approach, networks continue to recover returns and depreciation on assets that remain technically in service, even if they are under-utilised or no longer efficient to operate. In response, some distributors have sought to use accelerated depreciation (AD) across their networks to bring forward recovery. While this can support short-term financeability, it risks placing higher costs on a shrinking

customer base. It also does little to reduce stranded-asset risk if networks continue to invest or delay decommissioning.

JEC's proposal targets this problem by linking cost recovery to clear findings of redundancy. It would tie recovery to a transparent decision that specific assets, or sections of the network, are redundant and then cap the portion of remaining costs that consumers can be required to pay. ECA shares JEC's concern about consumer exposure and agrees that using network-wide AD as a default tool is not fit for purpose.

ECA supports the intent this reform. Our proposal tackles the same problem, which is how to manage cost recovery fairly in a declining system, but through a different mechanism. JEC's approach channels accelerated depreciation exclusively through redundancy decisions under Rule 85. ECA's approach retains a narrow role for Rule 89 to allow AD in limited and clearly defined circumstances where it can support a smooth price path and financial stability.

Both approaches aim to protect consumers from paying more than is fair for assets that are no longer used and useful. The key is that reform delivers effective consumer outcomes: a fair, transparent, and orderly approach to winding down the gas network.

1. Do you consider changes are required to the capital redundancy provisions in the context of the energy transition and an uncertain gas demand outlook? If so, what amendments do you consider are necessary?

Yes. Rule 85 currently provides too little guidance to the regulator on how and when to identify redundancy, and how costs should be shared. We support strengthening redundancy provisions to make them more usable in the energy transition. Amendments should include:

- a requirement for distributors to prepare a Redundancy Assessment in their access arrangement proposals, including economic information on asset life, utilisation, costs already recovered, and estimated stranding costs;
- a requirement for the regulator to make determinations based on that assessment, guided by published Redundancy Guidelines; and
- a principles-based framework that ensures any sharing of redundancy costs between distributors and consumers is equitable and transparent.

These changes would make redundancy a more practical and effective tool to manage decline, addressing gaps in today's framework.

2. Do you consider the definition of redundant assets should be amended as proposed by JEC to include: a. assets that are economically inefficient to use? b. anticipated redundant assets?

Economically inefficient assets: Yes, we consider there may be value in expanding the definition to cover assets that are economically inefficient to use. The current definition (requiring an asset to "cease to contribute in any way") is too rigid. In a declining-demand environment, an asset can remain technically functional but be economically inefficient to operate. Allowing the regulator to recognise such inefficiency would prevent remaining consumers from cross-subsidising unnecessary assets. As discussed below, however, it is unclear what the threshold would be for economically inefficient assets.

Anticipated redundant assets: Yes, but with safeguards. There is merit in identifying assets likely to become redundant in advance so that networks and regulators can plan early, lower cost exits. However,

this should not create an automatic presumption that consumers will fund those costs. Redundancy Guidelines should define objective criteria, such as clear utilisation thresholds and independent verification, to prevent gaming or premature cost recovery.

3. Do you agree with JEC's proposal that service providers and the regulator should use accelerated depreciation in conjunction with the redundant asset provisions only if used to address capital cost recovery risks or redundancy?

We agree with JEC that accelerated depreciation should not be a blanket mechanism for transferring undefined stranding risks to consumers. However, we consider making Rule 85 the sole gateway would be too restrictive, hence the rule change request we have submitted that seeks to address accelerated depreciation.

Stranded-asset risk often emerges from broad, system-wide decline rather than specific, isolated assets. For example, a gas distributor may see steady demand loss across its network due to policy-driven electrification. In such cases, redundancy assessments may be too narrow or slow to protect consumers. Conditional AD under Rule 89, with explicit consumer-protection conditions, gives the regulator a complementary tool to manage those risks transparently.

4. What do you consider would be the benefits and costs (for consumers, service providers and the regulator) of JEC's proposed approach to: a. defining and assessing asset redundancy, and b. allowing for accelerated depreciation to address capital cost recovery risks only in conjunction with the redundant asset provisions?

JEC's proposal offers some clear benefits for consumers. It creates a more direct and transparent link between costs and specific assets, ensuring that consumers are only asked to contribute to stranded asset costs once the regulator has made an explicit redundancy determination based on clear evidence. This would address a key problem in the current framework, where accelerated depreciation is sometimes used to recover costs associated with broad, system-wide risks that may never materialise. JEC's proposed 50 per cent cap on cost-sharing also provides a useful guardrail to limit consumer exposure. In addition, by tying accelerated depreciation to redundancy decisions, the proposal could encourage networks to identify and manage inefficient or underused assets earlier, facilitating more efficient decommissioning.

ECA supports the intent of JEC's rule change and agrees that stronger links between accelerated depreciation and redundancy assessments would improve transparency and accountability. Our focus has been on ensuring that any mechanism for managing stranded-asset risk includes appropriate consumer protections and policy settings, so that consumers are not paying an unfair share of transition costs. ECA's proposed amendments to Rule 89 aim to achieve this by making the use of accelerated depreciation contingent on clear criteria that ensure the framework operates consistently with broader transition objectives.

5. What are your views on JEC's alternative solution to outright prohibit the use of accelerated depreciation?

ECA agrees with JEC that consumers should not be treated as the network's insurer. Investors earn regulated returns because they accept some risk that assets may not be fully utilised over their lifetime. Allowing routine accelerated depreciation would unfairly transfer this risk to households and small businesses.

However, an outright prohibition on accelerated depreciation except in the case of asset redundancy risks leaving resolution of the stranded asset so late that only a small proportion of the current customer base remains to fund the customer portion of the remaining RAB. JEC's proposal still allows 50 per cent of the remaining asset value to be recovered from customers. Given that at least 50 per cent of the remaining value of the redundant asset is quarantined from recovery, and thus crystallises a loss for the network's owners, networks may be unduly deterred from carrying out a redundancy assessment on a timely basis. And in practice, given low levels of opex associated with specific assets, a functioning pipeline may not reach the threshold for economic redundancy until very low levels of utilisation are reached.

This creates a risk that redundant assets remain in service longer than is efficient, with consumers continuing to pay for assets that are no longer fully used. The Commission could consider clear triggers and incentives for redundancy assessment to ensure the framework delivers timely and fair outcomes for consumers.

To better manage this, ECA proposes a conditional approach under which accelerated depreciation would only be permitted where strict consumer-protection conditions are met, where networks are actively reducing future stranding risk, and where the regulator can demonstrate that consumers are better off than under the alternatives, including redundancy, deferral, or write-down. This ensures accelerated depreciation remains a targeted tool for managing transition risks, not a default mechanism for transferring investor risk to consumers.

Question 7. Are new planning requirements necessary?

1. Do you consider new planning-related reporting obligations are required in the NGR?
   a. What information should be reported and for what purpose?
   b. what should be the reporting frequency?
   c. what pipelines should the requirements apply to,: scheme, non-scheme, distribution, transmission?
2. What do you consider would be the benefits and costs of ECA's proposed reporting requirements (for consumers, industry, gas and electricity network businesses and the regulator)?
3. Do you consider that any alternative solution would better promote the long term interest of consumers?

1. Do you consider new planning-related reporting obligations are required in the NGR?

Yes. As outlined in our rule change proposals, there is limited public information currently provided by gas distribution networks, particularly compared to electricity networks. This makes it difficult for stakeholders to evaluate capex business cases, identify and assess opportunities for strategic decommissioning and coordinate local electrification programs.[17] In the context of the transition and gas network decline it is particularly important that distribution businesses plan for the future of their networks, as well as provide sufficient public information to enable the range of stakeholders with a stake in the future of gas networks and local gas use to undertake their own planning and ensure costs to consumer are minimised.

[17] ECA, Rule Change Request: New gas planning requirements, 15.

1a. What information should be reported and for what purpose?

As outlined in our rule change request, ECA considers that the Rules should be amended to:

- establish a **Gas Annual Planning Review**, with the Rules setting out the scope of the review and the appropriate forward planning period
- require a **Gas Annual Planning Report** (GAPR), with the Rules setting out the matters required to be addressed in the GAPR, the deadline for publishing the GAPS, and specify how stakeholders can contact a relevant representative of the network about the report.

The Rules should require that each service provider with a declared distribution system should carry out the Review and develop a GAPR for its full declared distribution system.

The information to be reported in the GAPR should include:

- the appropriate forward planning period (per our rule change we think 20 years is preferable)
- the useful life of gas distribution network assets
- demand forecasts – having regard to the current and forecast number of customer connections and disconnections, their energy consumption, and relevant legislation or regulations of a participating jurisdiction that may impact the forecasts
- potential or planned augmentation and replacement projects and the drivers for these (asset age, demand, reliability standards, regulatory requirements, etc)
- alternatives to potential investment projects and where these are inhibited by regulatory requirements
- underlying assumptions, subject to confidentiality requirements
- details of a consumer engagement strategy and attempts to elicit demand response.

We note the Commission's observation that, '[r]eleasing 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'. We agree that the information to be published needs to meet this objective and we consider that the information we have suggested is included in the GAPR is appropriate and necessary for this purpose. However, we would welcome further suggestions from the Commission and other stakeholder submissions that the Commission will receive through this process on other information that could be included to enable this objective to be met.

1b. What should be the reporting frequency?

As outlined in our rule change request, we suggest the GAPR is published annually, however not all outputs of the GAPR necessarily need to be published annually.[18] A complete forecast and plan for the future of the gas network should be published every two years, but the alternate years could include simpler statistical reporting on gas network use and disconnection.

We note the Commission has foreshadowed possible changes to frequency of access arrangements. The frequency of reporting could also be tied to any revised access arrangement cycle. For example, if access arrangements were to move to a two-year cycle, the 'full' GAPR and access arrangements could be published in alternating years to provide a built-in checking process and ensure close alignment between these processes.

[18] ECA, Rule Change Request: New gas planning requirements, 17.

1c. What pipelines should the requirements apply to: scheme, non-scheme, distribution, transmission?

Per our rule change request we consider that the planning requirements should apply to all distribution network pipelines. While our rule change has focused on distribution networks, acknowledge the Commission's observation that declining gas demand could have implications for transmission pipelines and consider there is merit in considering extending the planning requirements to transmission.

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

We have outlined the benefits, costs and other impacts of the rule change in our rule change request.[19] In short these are:

Consumers will benefit from better and more coordinated network planning, which will provide greater visibility of opportunities to minimise expenditure and therefore cost impacts for consumers. Consumers will also have advance notice of when gas infrastructure might end, to avoid ill-timed investments in replacing gas appliances.

Industry will benefit from a more efficient transition and increased confidence that gas networks are responsibly and publicly planning for the future of their networks. Better coordinated planning might reduce the potential for unexpected government policy decisions that impact on industry investment and certainty. The costs to industry should be modest as the information required under the GAPS should already be available to network businesses. To the extent that any costs are significant, we consider this is justified for network businesses managing an asset base of over $11 billion facing significant uncertainty.

Electricity distribution networks will benefit from greater understanding of when additional load might come to their system.

Regulators and policymakers will benefit from greater understanding of networks' plan for their future and improved information on which to make evidence-based regulatory and policy decisions that promote the long-term interests of consumers. The GAPR will also be a useful input into access arrangements, as a publicly available source of key forecasts and assumptions underpinning gas network businesses' proposals. This has the potential to streamline or simplify regulators' assessments of access arrangement proposals.

3. Do you consider that any alternative solution would better promote the long term interest of consumers?

There are two *additional* options that we think would supplement our rule change request (rather than being an alternative to it):

- demand forecasts for distribution networks could be independently undertaken by, or informed by, another body such as the AER

[19] ECA, Rule Change Request: New gas planning requirements, 18-19.

- the National Gas Rules could include a planning and consultation framework for strategic decommissioning.

Independent demand forecasting

While our rule change request recommends distribution networks include details of demand forecasts, such forecasts could also be developed independently by an appropriate body such as the AER, informed by information from the network businesses, jurisdictions and other market bodies. While this forecasting could also be done by AEMO we think the network-level focus means this may be more suited to the AER. While jurisdictions may have information on demand forecasts we think this should be an input into an AER-led process, rather than jurisdiction-led, as this will avoid the risk of politicisation of demand forecasting.

This could simplify access arrangement processes by obliging network businesses to adopt the demand forecast determined by the AER, rather than businesses developing such forecasts through the access arrangement process and the AER needing to assess these as part of that process.

Strategic decommissioning

We note the Commission's comment that, 'decommissioning of gas assets may need to be subject to a specific planning assessment and consultation framework (and not just additional information requirements on gas distributors)...It is not clear how ECA sees the GAPR as playing a role in any decommissioning process or whether this should be subject to separate reporting.'

We agree that there may be a need for a more detailed framework in the National Gas Rules for planning and assessing strategic decommissioning projects.

The intention of the GAPR is to provide the level of information that would be necessary to facilitate and identify opportunities for strategic decommissioning.[20] This includes requirements for the GAPR to include details of planned replacement or augmentation projects that could be avoided by strategic decommissioning.

However, the GAPR itself would not dictate how strategic decommissioning projects would be planned, assessed and consulted on. We agree that there may be a need for such a framework. While we recognise that a full decommissioning framework may need to be subject to a future rule change request, in assessing the current rule change requests we think it is appropriate for the Commission to consider how planning requirements might interact with such a framework and to lay the groundwork for that to happen.

At a high level the matters that we consider would need to be included in a decommissioning framework:

- At what scale(s) a strategic decommissioning project could be carried out
- The process for identifying a specific prospective project – who should take the lead, what if any stakeholder consultation or collaboration should take place.
- The process for determining if a specific project should go ahead – who should be the decision maker, what if any stakeholder consultation is required before a decision is made.

[20] ECA, Rule Change Request: New gas planning requirements, 16, 19.

- What notice period should affected customers and other relevant stakeholders (e.g. local and jurisdictional government, local DNSP) be given of a specific project to allow adequate time to prepare for the need to find alternative energy sources (primarily electrification)?
- What are the communication protocols to ensure that all affected parties have received timely notice and then for ongoing communication re reminders, support packages for customers, confirmation of whether they have made the change in time, etc.?
- Can customers who would prefer to keep their gas connection veto the project?
- What is the support package for affected customers, and should it allow for customers who remain committed to using gas to convert to bottled gas?
- How and by whom is the support package funded?
- Consideration of the costs incurred by the gas network carrying out the project and how to make sure their incentives are aligned with the overall net benefits of the project.
- Post project protocols to confirm all affected customers have an ongoing replacement energy source in place.

A strategic decommissioning framework would also need to consider how this would interact with jurisdictional obligation to supply arrangements. We consider that there may be circumstances in which it is appropriate for the obligation to supply to be disapplied, but this should be in the context of a clear decommissioning framework that provides the necessary consumer protections and certainty for consumers and networks.

Question 8. Would a longer-term outlook on the gas transition support better regulatory decision-making?

1. What do you consider would be the costs and benefits of requiring service providers to provide demand and expenditure forecasts over a longer period than the relevant access arrangement period? What would be an appropriate longer-term period (e.g. 10, 15 or 25 years)?

Yes, we agree that a longer-term outlook on the gas transition is necessary to support better regulatory decision-making. Our proposed rule changes are aimed in part at achieving this, including by requiring the GAPR to include details of demand forecasts, asset lives, planned augmentation and replacement projects and alternatives to investment, over the forward planning period (which we have suggested could be 20 years).

This could be extended to expenditure forecasts over a similar period. These would be distinct from the expenditure *proposals* contained in access arrangement submissions but presumably would be linked, i.e. the Rules could require distribution businesses to explain how their expenditure proposals align with or vary from their expenditure forecasts.

The benefits and costs would be similar to what we have already outlined in relation to the GAPR (see Question 7).

Workstream 3: Pricing

Question 9. Are changes to reference tariff variation mechanisms necessary?

1. Do you consider the NGR should provide more guidance to the regulator on when different reference tariff variation mechanisms (e.g. revenue cap vs price cap) should be used by service

providers to appropriately allocate intra-period demand risk between the service provider and users?

2. If so, what would be the costs and benefits to consumers, service providers and regulators of providing more guidance in the NGR and/or bringing forward the regulator's decision on the applicable reference tariff variation mechanism?

It would do no harm to include more guidance for the regulator on when to use different tariff variation mechanisms, though we do not think it is essential to do so provided the regulator retains sufficient discretion to take account of the full circumstances of each access arrangement. We have recommended elsewhere in this submission that access arrangement periods should generally be shorter and that the AER could be directly responsible for demand forecasting. Both of these proposals would, likely significantly, reduce the forecasting risk that might arise from the choice of tariff mechanism.

There are several considerations in deciding whether a price cap, a revenue cap or a hybrid best satisfies the NGO. The AER considers many of them in its access arrangement decisions and has also published a standalone paper on the subject: *Review of gas distribution network reference tariff variation mechanism and declining block tariffs.*[21] This paper notes that "In the case of gas distribution network volumes, distributors are better placed to manage volume risk than individual customers,"[22] which is consistent with the economic principle that risk should sit with the party best able to manage it. Implicit in this assessment is that volume changes do impose risks on distributors because costs do not vary in line with revenues (if they did then profits would be constant, and volume variation would not be risky). This seems likely to be the case, and so our considerations are contingent on this assumption.

A price cap incentivises the distributor to do two things: to under-forecast volumes in its access arrangement, and to find ways to increase volumes once the access arrangement is underway. Either of these will lead to actual volumes exceeding forecast volumes and the distributor making more revenue, which if costs are relatively invariant to volumes, results in more profit. Under-forecasting is limited by the regulator's ability to spot this and correct the demand forecasts on which the price cap is based. The AER cannot confirm that it is always able to do this, noting "It may be that we are approving volume forecasts that are too low."[23]

The AER's performance reporting indicates that actual volumes and thus actual revenues have exceeded expectations fairly consistently for over a decade (although the latest year's data shows actual and forecast volumes to be very similar).[24] This suggests that distributors have historically been well able to derive extra revenue from volume outperformance.

It should be noted that over the period, gas network revenues per customer have also decreased, reflecting the benefit to customers of network-wide volume growth with no concomitant cost increases. However, this trend may have come to an end, at least in Victoria and ACT as the implications of gas substitution policies and allowed accelerated depreciation come into effect.

In any case, whether or not the incentives for distributors to grow their network have delivered benefits to customers that justify the additional profits, this incentive is no longer appropriate. Such benefits are unlikely to continue, given the likelihood that volumes are on a permanent downturn. In principle, if distributors could slow the rate of decline, this would slow the rate of price increases, but that does not seem a desirable outcome in light of the need to decarbonise and that this is increasingly being reflected

[21] AER, 2023, Review of gas distribution network reference tariff variation mechanism and declining block tariffs
[22] Ibid, p17
[23] Ibid, p15
[24] 2024 Electricity and gas networks performance report, AER, 2025, p55

in government policies. It would seem dysfunctional to incentivise distributors to frustrate government policy.

The opposite approach of a revenue cap has potential downsides for customers. It exposes them to the risk that demand falls faster than forecast, which could manifest in rapidly increasing prices during an access arrangement.

Our other proposals discussed in this submission may affect these outcomes. Our recommendation for shorter access arrangement periods would mitigate against the risk of over or under forecasting, as there would be a frequent re-set. Our suggestion that AER be directly responsible for forecasting would remove the opportunity for distributors to under forecast.

Given all these factors, it is likely that it continues to be best that the AER is able to make a judgement based on the specific circumstances of each access arrangement. It seems that it already takes account of most of the relevant factors (including customer preferences). Accordingly, it would do no harm to include additional guidance to the regulator in the NGR though we do not see this as essential.

Question 10. Are changes to the tariff rules necessary?

1. Do you consider the NGR should include more or different guidance to service providers on how reference tariffs should be structured in the context of the energy transition?

In terms of tariff design, the existing principles may no longer be fit for purpose. In a context of declining demand, the long-run marginal cost of delivering an additional gigajoule of gas may effectively be zero. This does not in itself imply that tariffs should be focused on fixed charges. As more customers leave the network, the remaining customers will be those who do not have the agency or capacity to make this decision. Such customers are thus unlikely to be "able or likely to respond to price signals" as per Rule 94.

As a "no regrets reform", there would be merit in adding a clause to Rule 94 that requires tariff setting to take account of demand trends and policies affecting the use of the gas network. This would give both service providers and regulators the flexibility to consider where each network is on its pathway toward net zero.

The structure of tariffs will have growing implications for equity as demand declines. Shifting more revenue recovery into fixed charges can protect network stability but risks disproportionately impacting low-income households and renters who use relatively little gas or rely on partial electrification (for example, plug-in cooktops). Higher fixed charges also create a strong incentive for customers to remove their last gas appliance and fully disconnect, which may be efficient in a planned transition. Conversely, relying more heavily on volumetric charges could penalise households that cannot readily reduce consumption because of poor insulation, inefficient housing, or limited access to alternatives.

ECA does not take a position on the optimal balance between fixed and variable charges at this time but considers that both approaches have material equity implications that should be explicitly considered. The Commission should therefore ensure that tariff-setting guidance under Rule 94 requires the AER to test tariff structures against consumer outcomes, particularly affordability, fairness, and transparency.

Workstream 4: Planning

Question 11. Should the regulator be able to require shorter or longer access arrangement (AA) periods?

1. Do you consider the regulator should have more discretion to require a shorter or longer AA period than that proposed by the service provider? If so, what should be the criteria/principles to guide a regulator's decision on requiring a different AA period?
2. What do you consider would be the benefits and costs of aligning the timing of electricity and gas distribution decisions in relevant jurisdictions? What impacts would the alignment of the timing of these decisions have on regulators, service providers and stakeholders engaging in these processes?

1. Do you consider the regulator should have more discretion to require a shorter or longer AA period than that proposed by the service provider? If so, what should be the criteria/principles to guide a regulator's decision on requiring a different AA period?

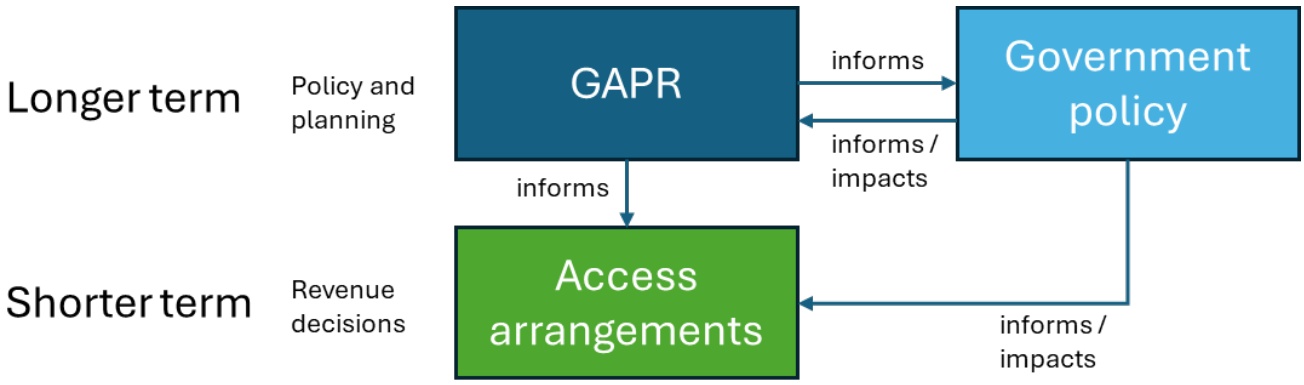
We agree that there is a need to consider the appropriate access arrangement period and flexibility for the regulator to vary access arrangement periods in the context of uncertain demand, which the Commission notes increases the risk of unforeseen events or material changes within an access arrangement period.

The Commission notes there is both a need for long-term planning and decision-making as well as flexibility to adjust to changes that occur within an access arrangement period. An additional consideration is the time and resources required for the networks, the AER and other stakeholders in developing, assessing and participating in access arrangement decisions.

Our planning rule change proposal is intended to ensure that there is adequate long-term planning to guide decision-making. As we have noted in our rule change request, it is intended that the GAPR will be a useful input into access arrangements as it will both 'set the scene' and be a publicly available source of key forecasts and assumptions underpinning gas distribution networks' proposals. It is important that these processes work together in an aligned way.

Access arrangements have a necessarily shorter-term focus. However, this shorter-term focus needs to be guided by appropriate planning for a longer-term transition. This can be achieved by ensuring alignment between the GAPR and access arrangement proposals. Ensuring this alignment will minimise any risk that access arrangements do not adequately support a longer-term outlook in decision-making.

Figure 2 | Proposed longer-term planning



In the context of declining demand, we think access arrangements should generally be shorter, particularly where there is information to indicate there is a risk of material changes within the access arrangement cycle.

We have proposed that the GAPR comprise a full forecast and plan every two years and a simpler statistical report every two years, on an alternating cycle. Access arrangements could also be undertaken on a shorter cycle to align with this.

There may be some potential to streamline the access arrangement process – for example, if the regulator were to be responsible for demand forecasting rather than assessing networks' forecasts, as suggested in response to Question 7 – but we anticipate access arrangements will remain a lengthy process.

There are practical challenges to short or rigidly timed access arrangement cycles. Adequate time is needed for the AER is to effectively scrutinise access arrangement proposals (and we note some of our rule change requests would require a greater degree of scrutiny) and for stakeholders to participate in these processes. Moreover, many of the most significant drivers of demand change, such as new government electrification policies, are unlikely to align neatly with regulatory cycles.

We think the preferable approach therefore is to provide AER with greater discretion to require shorter access arrangement periods, and for the Rules to contain guidance to the AER on when this should be considered (for example when there is a greater risk of material changes within the cycle). We do not think there is a strong rationale for increasing the length of access arrangement periods given the GAPR is intended to provide the long-term outlook that would inform access arrangements. An alternative to manage forecasting risk, without increasing administrative burden is to include a built-in mid-period review or check in for access arrangements (that does not need to be initiated by either a network business or the regulator). The review could be a streamlined process in which the regulator assesses whether the forecasts and assumptions underpinning the access arrangement remain valid, or if there are material changes requiring the access arrangement to be re-opened. If so, the re-opener process would be limited to considering any adjustments needed to account for those material changes.

In the United Kingdon, Ofgem experimented with an eight-year regulatory period with a mid-period review but ultimately abandoned the approach as too rigid in a fast-changing environment. This experience highlights that flexibility and responsiveness are more important than the nominal length of the period itself.

Given these trade-offs, ECA considers that the Commission should explore and test options for how the AER's discretion over access arrangement timing could best operate in practice. This could include:

- Examples or scenarios illustrating when shorter, longer or delayed access arrangements would best promote or cause harm to consumers – for instance, in response to large forecast change, major policy shifts, consumer behaviours and trends
- Analysis of administrative costs and timing constraints for shorter access arrangement cycles including likely resourcing implications for the AER and distributors
- Potential criteria or principles the AER could apply when exercising direction to delay shorten or extend an access arrangement period.

We acknowledge that more detailed access arrangement processes or additional planning and reporting requirements may be resource intensive for networks, regulators and stakeholders. However, the scale of this administrative effort should be seen in context. The cost and time involved in a single access arrangement process are minor compared to the overall cost of the gas system and the value of a well-managed transition. If these processes deliver clearer information, better scrutiny of expenditure, and fairer outcomes for consumers, they represent an efficient investment of regulatory resources. The real inefficiency lies in poor planning and misallocated capital that raises costs for consumers over decades.

2. What do you consider would be the benefits and costs of aligning the timing of electricity and gas distribution decisions in relevant jurisdictions? What impacts would the alignment of the timing of these decisions have on regulators, service providers and stakeholders engaging in these processes?

There are benefits in coordinating the timing of gas and electricity distribution decisions where practicable. Ideally these would be on a staggered cycle so that electricity distribution decisions can respond and take account of gas network decisions. The energy transition is making the two systems inseparable – as gas demand falls, electricity demand will increase, and policy choices about who pays for the transition will inevitable cross over between the sectors. As we have noted in our rule change request, electricity distribution networks will benefit from greater understanding of when additional load might come to their system.

Conducting gas access arrangements and determining slightly ahead of electricity determinations, such as by one regulatory year, would allow electricity distributors and regulators to incorporate updated information about gas connection trends, asset redundancy and regional demand shift into their own forecasts and expenditure assessments. A staggered approach would preserve the benefits of coordination while ensuring each sector has the flexibility to respond to emerging information. It would also reduce the risk that simultaneous determinations lock in assumptions that no longer reflect the evolving relationships between the gas and electricity systems.

Question 12. Are changes required to the re-opener provisions?

1. Do you consider changes are required to the current re-opener provisions? If so, what changes do you consider are appropriate in the context of the energy transition?
2. What would be the costs and benefits of making changes to the re-opener provisions?

We support giving greater flexibility to the AER to determine whether a re-opener is required and the scope of the re-opener, rather than these being initiated primarily by service providers. Consideration should also be given to re-openers being able to be initiated by civil society organisations if there is evidence of material harm to consumers arising from changes within an access arrangement period. The

key to facilitating other parties initiating reopeners is the timely publication of information on actual outcomes. To the extent that the GAPR includes the latest actual data as well as forecasts, this may be another benefit to the GAPR. If other parties have to rely on AER published data based on what it received from service providers, then this is currently on a slower cycle than would be necessary for other parties to promptly identify adverse outcomes from the current access arrangement.

If the built-in review suggested in response to Q11 is adopted this may reduce the need for re-openers as there will be greater scope for review of material changes within an access arrangement period without a re-opener needing to be initiated.

Question 13. Should there be changes to the existing or additional incentive mechanisms?

1. Do you consider modified or additional incentive mechanisms should apply to service providers in the context of the energy transition?

We consider that the incentive framework should be reviewed to ensure it remains fit for purpose in a system where demand is uncertain and clear emission reduction goals lie ahead. Current incentive schemes were designed for networks expected to grow and may now produce outcomes that are inconsistent with the objectives of an efficient and equitable transition.

As outlined in our responses to Questions 2, 3 and 4, existing capital and operating expenditure incentives continue to favour network expansion and capital-intensive investment. This bias discourages lower-cost or non-network solutions and limits the scope for proactive management of network decline. We have recommended reforms that rebalance incentives by recognising transition-related operating expenditure, enabling efficient decommissioning and requiring stronger planning and transparency.

Incentive mechanisms should focus on behaviours and outcomes that support consumers through the transition. For example, mechanisms could:

- reward networks for avoiding capital expenditure where non-network or strategic decommissioning options deliver lower overall costs to consumers;
- link financial rewards to efficient reduction of the regulated asset base, where this demonstrably reduces long-term consumer costs;
- provide incentives for data transparency and planning coordination, particularly through annual planning reports and collaboration with electricity distributors; and
- encourage consumer-centred performance, such as how well networks support households and small businesses to plan and electrify efficiently.

ECA does not support incentives that aim to preserve throughput or delay transition, as this would conflict with the NGO and increase stranded-asset costs and risks for consumers.

Given that the AER's existing incentive schemes, such as the Efficiency Carryover Mechanism (ECM) for opex (to incentivise cost savings) and the Capital Expenditure Sharing Scheme (CESS), were designed for networks in growth, there is merit in the Commission suggesting the AER review how these schemes operate in a declining demand context. This review could consider whether current mechanisms inadvertently discourage efficient downsizing, strategic decommissioning or coordination with electricity networks. It should also explore new incentives that reward networks for reducing costs through avoided capex or managed asset retirements, rather than simply underspending on existing programs.

Question 14. Could the proposed changes inefficiently incentivise pipeline elections?

1. Would any of the changes considered in this consultation paper alter the incentive for non-scheme pipelines to elect to become scheme pipelines?

In our view, the proposed changes are intended to drive greater scrutiny of service providers' proposals and to minimise their opportunity to transfer stranded asset risk to consumers via accelerated depreciation. In this light, it is not clear why these changes would make it more likely that a non-scheme pipeline would elect to become a scheme pipeline than under the current rules.

However, if the Commission considers there is a material risk of this occurring, the solution should not be to dilute consumer protections for scheme pipelines but to strengthen the process by which non-scheme pipelines elect to join the scheme. The Basslink conversion application, for example, highlighted the risks of allowing assets to move from merchant to regulated status without clear evidence of consumer benefit.[25] As JEC noted in its submission to the AER, the claimed benefits of conversion were uncertain, while the costs and risks to consumers were substantial and foreseeable by the asset owner.[26]

In general, if non-scheme pipelines seeking to forgo the freedom afforded to them by their current regulatory status for the additional constraints and reporting requirements of scheme pipelines, that would indicate that the regulatory framework for scheme pipelines is unduly generous to service providers in some way. One way to mitigate this would be to require pipelines to set out how the change would benefit their customers as a condition of approval, and then this outcome to be enforced through regulation (e.g. reduced tariffs for the first access arrangement post-election, implemented by setting the opening RAB at a level that resulted in tariff reduction.

Question 15. What can we learn from other jurisdictions/sectors?

1. Do you consider other changes to the regulatory framework for scheme pipelines are necessary to provide the regulator with the tools and appropriate level of discretion to manage the gas transition? If so, what would be beneficial?

ECA welcomes the Commission for examining international case studies early in this consultation and agrees that understanding how other regulators have responded to declining gas demand is valuable. However, the examples selected are not directly analogous to Australia. For instance, Europe's gas networks face a more acute and immediate transition challenge due to energy security risks following the shift away from Russian gas imports.[27] Australia, by contrast, benefits from abundant renewable electricity resources, high rooftop solar uptake, and growing electrification momentum across households and small businesses. These conditions allow for a more gradual, strategically managed phase-down of gas use. As a result, the need for accelerated capital cost recovery is less compelling here.

Research by Dr Glen Currie from Climateworks Centre reinforces this distinction showing that California's high energy costs stem from structural and governance choices, not climate ambition.[28] The main lesson for Australia is to pursue a simpler, better-coordinated transition grounded in clear national

[25] AER, 2025, Final decision: Basslink conversion | Australian Energy Regulator (AER)
[26] JEC, 2024, Submission to AER Basslink conversion application - Justice and Equity Centre
[27] Council of the European Union, 2025, Council agrees its position on rules to phase out Russian gas imports under REPowerEU
[28] Dr Glen Currie, 2025, Comparing the Californian energy transition with Australia available at: https://energyconsumersaustralia.com.au/sites/default/files/2025-10/website-doc-gill-owen-scholarship-2025-research-conclusions-glen-currie-updated-oct.pdf

rules, open markets and strong consumer protections, ensuring fairness and affordability as networks decline.

The key lesson from the case studies identified by the Commission is not to accelerate depreciation, but to first establish the policy and regulatory guardrails needed to protect consumers and guide an orderly transition. A statutory framework for planned decommissioning, mandatory planning and mapping requirements (including robust testing of non-pipeline alternatives), and clear consumer protection and equity measures should form the foundation. Within this framework, accelerated depreciation may then have a limited, conditional role where it demonstrably supports a fair, least-cost transition for consumers.

Question 16. Assessment framework

1. 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?

We broadly support the Commission's proposed assessment framework and agree that it provides a solid basis for evaluating how the rule changes promote efficient investment and fair outcomes for consumers. The focus on consumer protections, equity, and transparency is particularly welcome.

However, we consider there needs to be more clarity in how "outcomes for consumers" and "emissions reduction" are interpreted. The framework should recognise that consumers have agency and choice in how they meet their energy needs. Many households and small businesses are choosing to transition away from gas, and the regulatory framework should support these choices by enabling a fair, affordable, and coordinated shift to lower-emission options. Assessing consumer outcomes should therefore capture both the experience of those who remain on gas and those who are leaving it.

We also encourage the Commission to place greater emphasis on risk allocation and transparency. These are essential to ensure that consumers are not left paying for under-used assets and that regulators can properly test network proposals in an uncertain market.

[End of submission]

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