

30 October 2025

Ms Anna Collyer
Chair
Australian Energy Markets Commission

Dear Ms Collyer

Submission to the AEMC's gas networks in transition consultation paper (GRC0082)

Evoenergy welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC's) consultation on proposed rule changes to the National Gas Rules (NGR or Rules). We support the AEMC taking a holistic approach to consider interrelated elements of the framework.

Evoenergy supports a regulatory framework that is adaptive, equitable, and transparent. We urge the AEMC to consider the broader implications of the proposed rule changes and to ensure that any reforms promote the long-term interests of consumers while maintaining network safety, reliability, and investment confidence.

While we support the AEMC's proposed set of assessment criteria for carrying out its review, we consider the addition of 'flexibility' and 'innovation' would contribute positively to assessing costs and benefits of any rule changes under consideration.

Evoenergy considers the current regulatory framework is largely capable of accommodating the electrification transition and achieving outcomes that are in the long-term customer interests. Critical to achieving long-term customer outcomes under the regulatory framework is:

- Ensuring the fundamental principle unpinning the regulatory regime of reasonable opportunity to recover efficient costs is maintained. Any rule changes which act to limit or prohibit reasonable opportunity to recover costs would undermine investor confidence in the gas sector as well as regulated utilities in Australia more broadly. This would ultimately increase costs to consumers of essential services and put at risk the efficient investment necessary to deliver the essential services customers rely upon, today and in the future.
- Regulators taking early action and a long-term view under the regulatory framework to share the costs of capital investments over the greatest number of customers and from as early as possible in the transition period, to enable a fair, steady and equitable long-term price path.
- Ensuring the regulatory framework is flexible to accommodate jurisdictional policy differences and different network operating conditions. In some jurisdictions such as the ACT, policy measures to support net zero targets are setting the direction of the transition and materially driving the pace and scale of the transition away from the use of gas networks. In other jurisdictions, governments are actively supporting exploration of the use of renewable gas. The regulatory framework should not seek to drive to one future state or impose cross jurisdiction consistency in regulatory outcomes, particularly where this would undermine the policy settings of the different jurisdictions.

Evoenergy recommends three changes to the regulatory framework to better achieve long-term customer interest in the context of different jurisdictional approaches to energy transition:

- providing for early provisioning of network decommission costs through operating expenditure allowances, where there is a policy direction or obligation to incur these costs in future. This would enable costs to be shared among more customers over a longer period, better achieving a reasonable opportunity to recover costs and enabling a steady and equitable long-term price path (refer to section 2).
- explicitly requiring regulators to consider the relevant network operating conditions in making decisions on each regulatory element, particularly the tariff variation mechanism (refer to section 3a). This would ensure regulatory decision-making best reflects the relevant jurisdictional context, including jurisdictional emission reduction targets.
- recognising the evolving role of tariffs in gas networks through the energy transition by making changes to the NGR to remove the requirement to take into account long run marginal cost, which is not an appropriate measure for networks with declining demand (refer to section 3b).

While the regulatory framework is largely capable of achieving long-term customer interest, we note that in jurisdictions where policy settings are accelerating the transition away from gas over a relatively short time horizon, governments may need to play a role in supporting the regulatory framework to achieve both objectives of a reasonable opportunity to recover costs and prices which are fair, steady and equitable for gas customers throughout the transition.

The consultation paper helpfully identifies current thinking and approaches being employed around the world to manage capital cost recovery risks. Evoenergy encourages the AEMC, regulators and governments to consider how these examples might apply to comparable circumstances within Australia, again noting the importance of considering this in the context of different transition pathways in different jurisdictions. Importantly, we observe that there is precedent both nationally and internationally for governments to provide financial support when policy decisions limit feasibility of cost recovery of regulated assets while ensuring equitable customer outcomes and maintaining efficient investment conditions.

A long-term view in decision making, early action, and constructive collaboration between all parties, particularly in relation to the concerns raised in the rule change requests, will provide the greatest opportunity for a steady and equitable transition for all energy consumers.

Evoenergy supports the views expressed in the Energy Networks Australia submission. In addition, we provide the attached feedback on the four workstreams identified for this review.

We look forward to continuing to engage throughout this review. Please contact Gillian Symmans, Group Manager Regulatory Reviews and Policy (gillian.symmans@evoenergy.com.au) should you wish to discuss our feedback.

Yours sincerely



Megan Willcox
General Manager, Economic Regulation

Evoenergy's feedback on the AEMC's Gas networks in transition consultation paper

1. Capital cost recovery

Being provided with a reasonable opportunity to recover efficient costs is a fundamental principle of the regulatory framework.

Undermining this principle is contrary to the National Gas Objective (NGO) and Revenue and Pricing Principles (RPPs) and risks investor confidence in critical regulated infrastructure, particularly through the energy transition.

The current NGR provide for the use of established regulatory tools to manage recovery of capital investment to meet the NGO and RPPs enshrined in the National Gas Law (NGL). This includes re-profiling depreciation to better align with the economic life of the asset. In the case of assets that provide services to a market with declining demand, this results in bringing forward, or accelerating, depreciation to better align with asset utilisation. Evoenergy does not agree that this approach inappropriately shifts asset stranding risk entirely to consumers, as suggested by the rule change proponents. Better aligning depreciation recovery with an asset's economic life effectively retains the existing and intended risk sharing arrangements within a changing context, and manages the consequences of rapidly escalating gas network charges by providing more equitable risk sharing outcomes, both across current gas customers and those remaining in the future, and between gas customers and network businesses (Question 4).

The long-term interests of gas consumers and consumers of regulated infrastructure more broadly are best served by preserving the fundamental principle that gas network businesses should be provided with the reasonable opportunity to recover prudent and efficient costs.

Both the proponents and the AEMC note that this principle is not intended as a *guarantee* that regulated businesses will recover costs. However as provided for under the RPPs¹ and NGR² and noted by the AEMC, gas network businesses should have a reasonable opportunity to earn a return commensurate with the level of risk, as well as recover capital investment over the economic life of an asset. While this does not serve to guarantee full cost recovery, it should reflect the ex-ante nature of regulation, where gas network businesses have incentives to manage their businesses against reasonable forecasts used to determine approved revenues allowances at the time of a decision and share the benefits of this with consumers over the long-term through lower prices.

Removing this fundamental principle, either through limiting or prohibiting the use of accelerated depreciation, and/or the classification of redundant assets, would allow regulators to make decisions which intentionally *prevent* recovery of efficient costs and therefore conflict with the intent of the RPPs and achievement of the NGO.

Maintaining this foundational principle, and regulatory certainty more broadly, is critical to preserve confidence in investment in regulated infrastructure. As consumer demand for electricity network services continues to grow, investors will seek to ensure a return commensurate with the level of commercial and regulatory risk faced to build critical infrastructure within respective jurisdictional

¹ NGL, section 28(2).

² NGR 89.

operating environments. Consumer interests will be best served – both in terms of price impacts and safety, reliability and security of supply – by regulatory decision-making which reflects the level of risk intended by the regulatory compact that underpins investment in regulated infrastructure.

The current NGR can and should be applied to uphold the reasonable opportunity principle, having regard to long-term demand expectations, the obligation to provide gas network connection services (unless prohibited by a jurisdictional decision) while maintaining network safety and reliability, the stranded asset risk faced by businesses, and the long-term customer impacts. Rather than viewing this principle as a mechanism to ‘shift risk’ to customers, we consider early action by businesses and regulators to reprofile depreciation provides both a reasonable opportunity to recover costs and delivers more equitable outcomes for consumers by sharing these costs across a larger customer base and longer period.

In taking this view, we do not support the AER’s recent approach to gas network decision-making which determines an ‘acceptable’ price path over the short-term period to back-solve the depreciation allowance.³ This arbitrary approach not only lacks transparency and economic rigour, but ignores the long-term impacts on customer bills while increasing a network’s stranded asset risk without a return commensurate with the associated regulatory and commercial risks specific to the network’s operating context. If a back-solved depreciation approach capped at short-term price path levels were to be adopted by the AER for Evoenergy’s 2026–31 access arrangement decision, this would fail to provide a reasonable opportunity to recover efficient costs, and therefore fail to reflect the requirements of the RPPs. In contrast, Evoenergy’s proposal of aligning asset lives with remaining economic lives, together with re-profiling depreciation using the sum of years’ digits approach applied by Ofgem in the United Kingdom provides for an opportunity for recovery of the capital asset base while managing customer bill impacts over the long-term based on modelling over the transition period to the legislated target of net zero by 2045.⁴

In no way does Evoenergy’s proposed approach guarantee full cost recovery – if gas demand falls faster than forecast, Evoenergy is at risk of materially under-recovering its past investment costs. Our access arrangement proposal explores a scenario to demonstrate this risk. In this illustrative scenario gas demand falls faster as a result of the introduction of new policies to accelerate the transition to achieve interim and 2045 net zero emissions targets, or stronger than anticipated customer sentiment, and a hypothetical policy-imposed ‘capping’ of a 50 per cent increase relative to 2025-26 network charges is applied.⁵ In this scenario, Evoenergy would not recover \$95 million, or 23 per cent of the 2026-27 opening capital asset base. Without the hypothetical capping of network charges, under this demand scenario, retail bills would need to increase sharply to unsustainable levels to enable full cost recovery – leaving Evoenergy exposed to a material stranding risk.

We note however that there may be some circumstances where there is inadequate time and customers remaining before a targeted network shutdown, such that providing a reasonable opportunity to recover costs through the regulatory framework will be practically challenging, given the significant price impacts on remaining customers. For networks facing rapid demand decline,

³ See for example the AER’s decisions on Jemena Gas Networks 2025–30 and AusNet Gas Services 2023–28, Australian Gas Networks 2023–28 and Multinet Gas Networks 2023–28 (collectively the Victorian gas distributors decision).

⁴ Evoenergy (2025). [ACT and Queanbeyan-Palerang gas network access arrangement 2026–3 – Access arrangement information – Attachment 6: Depreciation](#), June.

⁵ Ibid, pp.31-33.

innovative funding solutions beyond the regulatory framework may be required to provide fair, reasonable and sustainable prices for customers throughout the transition. For example, through our 2026–31 gas network access arrangement engagement program stakeholders raised the idea of costs being shared across energy users, or taxpayers more broadly.⁶ We note that the need for funding solutions beyond the current regulatory framework would increase if decisions made within the framework focus on short-term price impacts and therefore narrow the opportunity for cost recovery within the regulatory framework.

2. Expenditure assessments

a. Capex criteria

Adequate safeguards exist to ensure capex is efficient and proposed changes to the capex criteria are unnecessary.

While gas networks continue to serve customers, there will be a need for ongoing expenditure to ensure safety and regulatory obligations are met and service standards are maintained. Nevertheless, in circumstances where demand for gas services is declining, efforts must be directed at reducing, rather than adding costs, including regulatory costs, that will ultimately be recovered from customers.

For Evoenergy, safety comes first and drives our decision-making. In considering changes to the NGR including the expenditure criteria, it is critical that gas network businesses retain adequate funding to maintain or, where efficient to do so, improve network safety for our customers, employees and the public.

The proposed changes to the capex criteria are unnecessary as adequate safeguards exist to ensure that this necessary capital investment is efficient – both in terms of the existing capex criteria, as well as a gas network business’ consideration of policy and market conditions for minimising further asset stranding risk in their investment decisions (Question 2).

For gas network businesses experiencing a material decline in demand and where jurisdictional policy to phase out gas exists, investors face a very strong incentive to not over-invest so as not to add to the material asset stranding risk already faced. Similarly, gas network businesses making investment proposals in the pursuit of viable renewable gas options, which are now included as ‘covered gases’ in the National Gas Law (NGL), are doing so against the same strict criteria that apply to other capex, and are subject to the same scrutiny by regulators.

⁶ See for example, [Evoenergy’s Community Panel Recommendations Report](#), August 2025

b. Opex criteria

The opex criteria should be amended to provision for future decommissioning costs where a jurisdictional regulatory obligation, or statement of policy exists.

Where gas demand declines and governments set an electrification policy, some gas networks will face the need to plan for the decommissioning of part, or all, of their network assets. Planning and executing decommissioning arrangements that meet the safety, environmental and public amenity requirements of governments and the community in a timely and convenient manner will be highly complex and will require considerable time and investment.

The ACT Government has indicated a phased decommissioning of the gas network will occur between 2035 and 2045.⁷ Until this time, Evoenergy expects that its entire gas network will continue to be fully utilised and operational to service the gas needs of its declining customer base until all, or nearly all, customers in an area have ceased using gas.

The ACT Government and Evoenergy have commenced scoping studies to understand network decommissioning scenarios, requirements and costs. While the complexity and cost will ultimately be driven by a range of factors, including whether local regulations allow for a staged or ad-hoc decommissioning, early estimates indicate decommissioning costs for Evoenergy (i.e. not including customer-side costs) could be in the order of around \$100 million. Importantly, this expenditure will be incurred at a time when there are few or no customers remaining on the network.

Under the currently regulatory framework, gas network decommissioning costs would only be recoverable through regulatory allowances in the period in which they are expected to be incurred. Consequently, the current regulatory framework does not provide a reasonable opportunity to recover network decommissioning costs because by the time these costs will be incurred there will be too few customers remaining on the network to practically recover the costs through gas network prices. This is a significant deficiency in the existing regulatory framework in the context of the energy transition underway.

The regulatory framework should therefore allow for the provisioning of future network decommissioning costs, in circumstances where relevant jurisdictional policy intent has been specified. Specifically, Evoenergy recommends that where there is a jurisdictional regulatory obligation, or clear statement of policy intent,⁸ to decommission the network, the opex criteria should allow for forward provisioning of decommission costs to be included in opex allowances ahead of when these costs are incurred. This would provide the opportunity to share the costs of decommissioning over a larger customer base and a longer time horizon (Question 3). This approach is consistent with financial accounting requirements to recognise a provision where there is a present obligation as a result of a past event that will require an outflow of resources in the future to settle the obligation.

We note however that in some circumstances, such as when there is inadequate time remaining before a targeted network shutdown, provisioning for these costs through regulated revenues would still be inadequate. The late provision of material decommissioning costs would place further cost pressure on remaining gas customers and accelerate the exit of customers, leaving little chance of

⁷ ACT Government (2024). [The Integrated Energy Plan 2024–2030: Our pathway to electrification](#), June, p. 19.

⁸ Such as is set out in the ACT Government’s Integrated Energy Plan.

recovering these costs. For networks facing rapid demand decline, innovative funding solutions beyond the regulatory framework will be required to safely decommission network assets while enabling a reasonable opportunity for cost recovery alongside fair, reasonable and sustainable prices for customers. Evoenergy stresses the need for early planning, collaboration and action across regulators, governments and businesses to best serve the long-term interests of consumers.

c. Incentive mechanisms

Strong incentives and regulatory arrangements already exist for gas network businesses to invest efficiently and maintain service standards. Further changes to incentive scheme provisions are not necessary.

The current NGR provide sufficient flexibility for the inclusion of incentive schemes which reflect the circumstances of individual network businesses and are based on well-established electricity network incentive schemes. While the NGR do not include a standalone service target performance incentive scheme, such as exists for electricity networks, we note that the capital expenditure incentive mechanism currently applying to Evoenergy's gas network (as well as other gas networks) includes a contingent payment index linked to the achievement of service standard performance targets (Question 3.3).

There exist strong incentives for gas network businesses to invest efficiently and maintain service standards in declining markets or markets facing increased competition from other fuels to avoid accelerating customer exit from the service. Gas network businesses also adhere to strict regulatory obligations and licence conditions and a failure to maintain service standards would undermine consumer confidence in the business and result in gas customers abandoning the network at a faster pace

3. Prices

a. Tariff variation mechanism

When considered holistically, the requirements of the NGL and NGR provide comprehensive guidance and sufficient flexibility for the businesses to manage demand forecasting risk.

An addition to the NGR requiring explicit consideration of the specific circumstances of the gas network business would allow the AER to give effect to its 2023 decision to consider TVM proposals on a ‘case-by-case’ basis.

Bringing forward the decision on the TVM to the RSP stage presents significant challenges.

The AEMC has sought views on whether existing regulatory tools are appropriate to manage demand risk. In particular, whether providing more guidance to the AER on the use of the tariff variation mechanism (TVM) could assist with better accounting for uncertainty and demand risk (Question 9).

We note that the risk exposure of the TVM over an access arrangement period predominantly relates to demand *forecasting* risk – that is the revenue risk associated with the demand forecast at the time a decision is made being materially different to actual demand over the period. Importantly, the TVM does not address demand risk, being the revenue risk associated with declining demand for gas.

The existing regulatory framework provides clear guidance to regulators on managing uncertainty and risk, particularly in relation to the method to vary tariffs which contributes to the achievement of the NGO.⁹ Additionally, the NGL provides that reference tariffs should allow for a return commensurate with the regulatory and commercial risks involved in providing reference services.¹⁰ Evoenergy considers however that an explicit requirement on regulators to consider the relevant operating conditions, market and policy circumstances of gas network businesses (i.e. the level of demand forecasting risk faced) together with the risk compensation allowed for that gas network’s regulatory determinations would be a constructive amendment to the NGR.

In its 2023 decision, the AER observed that it would consider TVMs on a ‘case-by-case’ basis to allow it to better account for the differing levels of reliance on natural gas as an energy source across different jurisdictional markets, different policy settings applicable in each of those markets, and the views of distributor-specific stakeholders.¹¹ The AER has also recognised that regulatory approaches may differ across jurisdictions because the circumstances and demand risks that each regulated gas network faces is unique to its operating environment, the configuration of assets and the composition of its customer base.¹²

When considered holistically, the requirements of the NGL and NGR provide comprehensive guidance and sufficient flexibility for the AER to make TVM decisions that account for the differing circumstances of each gas network business, and allow for the management of demand forecasting risk. An addition to the NGR to require explicit consideration of the individual circumstances of the

⁹ NGL, section 28(2), NGR 97(3)

¹⁰ NGL, 24(5)

¹¹ AER (2023). *Review of gas distribution network reference tariff variation mechanism and declining block tariffs*, Final decision October, p. 1.

¹² AER, [Regulating gas pipelines under uncertainty](#), November 2021, p. viii

gas business, in place of ‘any other relevant factor’¹³ would better allow the AER to give effect to its 2023 decision to consider TVM proposals on a ‘case-by-case’ basis. This is particularly important in Evoenergy’s context where demand forecasting risk in the 2026–31 period is higher than other jurisdictions, given our unprecedented pace of change and unique customer and demand characteristics.

Evoenergy’s notes recent commentary from the AER that it is placing emphasis on regulatory precedent rather than other aspects of guidance set out in the regulatory framework.¹⁴ Evoenergy further notes NGR 97 (3) requires consideration of the ‘desirability of consistency between regulatory arrangements for similar services both *within and beyond* the relevant jurisdiction’¹⁵ and that the application of a revenue cap to our gas services is consistent with the price variation method of the ACT’s electricity network.

An amendment to the NGR to require the regulator to consider jurisdictional context¹⁶ would improve outcomes for consumers by ensuring the TVM is set to reflect a level of risk commensurate with the demand forecasting risk and risk mitigation opportunities relevant to an individual gas network business’s circumstance.

The AEMC also sought views on whether the NGR should be amended to require gas distribution businesses to propose a TVM at the reference service proposal stage (RSP) (i.e. twelve months ahead of the access arrangement review date) giving effect to the AER’s 2023 decision.¹⁷ As one of the first businesses to submit a combined reference service, TVM and tariff structure proposal following the AER’s decision, Evoenergy’s experience is that requiring a decision on the TVM at the RSP stage presents significant challenges, given the interrelationship with other elements (such as the building blocks and demand forecasts) and the need for informed and meaningful engagement with stakeholders.

Evoenergy engaged with stakeholders on this complex regulatory economic concept early in the process, and well in advance of having a complete view of its revenue estimate and demand forecast. In these early pre-RSP sessions our consumers and stakeholders sought a clearer view of the expected bill impacts of different TVM approaches to assist their understanding and assessment of the relative merits of the different approaches. While we were able to provide illustrative examples in early engagement sessions, not being able to fully demonstrate these impacts presented challenges for both Evoenergy and our stakeholders. It was necessary to revisit this topic in later sessions¹⁸ to demonstrate the price impacts of various TVM approaches in the context of the overall revenue requirement and our operating environment for the 2026–31 period and beyond.

¹³ NGR 97(3)(e).

¹⁴ See for example AER (2024). *Evoenergy Gas Distribution Determination 2026 to 2031, Reference Service, tariff variation mechanism and tariff structure, Final decision*, November, p. 2.

¹⁵ NGR 97(3)(d).

¹⁶ This could be achieved by for example, clarifying or adding to the ‘any other relevant factor’ limb of NGR 97(3).

¹⁷ AER (2023). *Review of gas distribution network reference tariff variation mechanisms and declining block tariffs, Final decision*, October.

¹⁸ Sessions held in March and May 2025 ahead of the submission of the access arrangement proposal.

b. Tariff structures

There should remain flexibility for gas network businesses to propose and for regulators to assess tariff structure on a case-by-case basis, having regard to the network's circumstances and interactions with the TVM.

The NGR should recognise the evolving role of tariffs in gas networks through the energy transition and the objectives of supporting cost recovery, managing demand forecasting risks, maintaining stable prices, and promoting long-term equity during the transition.

Evoenergy recommends that:

- ***the requirement under Rule 94(4)(a) that tariffs take into account long run marginal cost should be removed, since this is not an appropriate measure for networks with declining demand;***
- ***the operation of Rule 94(5) should be broadened to require that tariffs be adjusted to allow a service provider to recover expected revenues, independent of this being needed due to subrule (4) or achieving efficient patterns of consumption; and***
- ***the NGR should support flexibility and not be more prescriptive or provide more guidance to gas network businesses on appropriate tariff designs.***

Evoenergy supports the AEMC's consideration of tariff structures in the context of regulatory tools to manage demand forecasting risk within an access arrangement period (question 10). It is important that the AEMC and regulators give due consideration to the relationship between tariff structures and other regulatory tools, included the TVM, in a gas network business's ability to manage demand forecasting risk over an access arrangement period.

The current tariff provisions under the NGR are largely based on promoting economic efficiency, including by signalling long-run marginal cost (LRMC) and supporting efficient patterns of consumption. These principles no longer provide a useful framework for Evoenergy's gas network. With declining demand, no foreseeable capacity expansion, and the ACT Government's policy to commence staged network decommissioning from 2035, LRMC is not a well-defined or relevant measure. A marginal increase in demand does not result in higher long-run costs, and therefore LRMC cannot be credibly signalled through network tariffs. Instead, Evoenergy's revenues are increasingly focused on the recovery of past capital costs and the largely fixed costs of operating, and eventually decommissioning, the gas network.

We therefore consider it appropriate that the requirement that tariffs must take the LRMC into account¹⁹ be removed.

Rule 94(5) of the NGR allows tariffs to be adjusted to ensure recovery of expected revenues, but only where this is necessary due to the operation of subrule (4), which requires that tariffs be set with regard to LRMC, transaction costs, and customer responses to price signals. It is also required that any adjustment to tariffs under Rule 94(5) be achieved with minimum distortion to efficient patterns of consumption.

Evoenergy considers the NGR should recognise the evolving role of tariffs in gas networks. For Evoenergy's network, the focus of tariff design is shifting from signalling marginal costs towards

¹⁹ NGR 94(4) and 94(5)

enabling opportunity for cost recovery, managing demand forecasting risks, maintaining stable prices, and promoting long-term equity during the transition.

Moreover, the concept of efficient consumption levels is also challenging to define in the presence of a policy mandate to phase-out gas, and in the absence of marginal cost drivers for the network. Evoenergy’s customer research for its 2026–31 access arrangement proposal shows that gas usage and electrification decisions are mainly driven by non-price factors such as customer appliance preferences, emissions considerations, site feasibility for electrification, and government policy.²⁰ Network prices have a limited effect on consumption decisions, especially once diluted in retail bills. This means that adjustments to tariff structures or rebalancing fixed and variable charges are unlikely to materially influence customer behaviour.

We therefore recommend that Rule 94(5) should be broadened to only require that tariffs are adjusted to ensure recovery of expected revenues and removing the current references to subrule (4) and efficient levels of consumption.

Evoenergy emphasises the important interplay between tariff structures and the TVM, particularly as it relates to managing demand forecasting risk and capital cost recovery. Under price cap or hybrid TVMs, tariffs are one of the few tools available to stabilise revenue recovery and manage bill impacts for customers, particularly in the context of a ban on new connections and policy direction to phase out gas. This may involve gradually shifting revenue recovery from tariff components with declining or volatile volumes to those providing greater certainty. While Evoenergy recognises the tension between declining block structures and emissions reduction objectives, flattening tariffs too much or too quickly removes an important tool for enabling a reasonable opportunity for efficient revenue recovery and ensuring equitable bill outcomes for customers as demand declines.

We do not consider that the NGR should be more prescriptive or provide more guidance to gas network businesses on appropriate tariff designs in the context of the energy transition (Question 10). We support the need to retain flexibility for gas network businesses to propose and the AER to assess tariff structure on a case-by-case basis having regard to the network’s circumstances and interactions with the TVM.

Future tariff considerations should recognise the need to provide networks with a reasonable opportunity to recover efficient costs in an environment of uncertain and declining demand. As demand forecasting uncertainty increases and gas network businesses’ risk management opportunities are limited, we emphasise the need for carefully-considered and gradually-implemented changes to tariff structures which take into account the impacts on different customer types, and a gas network business’s ability to manage risk through the energy transition.

The NGR should also continue to support tariffs that remain practical and simple, avoiding additional transaction costs²¹ and complexity for customers and retailers already facing complexities and cost pressures during the energy transition.

²⁰ The Centre for International Economics, *Price elasticity of demand for natural gas*, Appendix 2.2 of Evoenergy’s Access Arrangement Proposal 2026-31, June 2025.

²¹ This requirement is embedded in Rule 94(4)(b)(i)

4. Access arrangement mechanics and planning

a. Long-term outlook

Existing reporting requirements and incentives provide sufficient surveillance of the long-term energy transition. Additional regulatory reporting obligations would add costs for customers and may limit the ability for long-term planning to be tailored to the circumstances of individual networks and their customers.

Evoenergy supports, in-principle, long-term planning to inform decision-making to support the long-term interests of gas consumers. However, it is not necessary to make this a requirement under the NGR. Instead, we consider it to be the responsibility of gas network businesses to undertake and share long-term planning as appropriate in their circumstances to support regulator decision-making and stakeholder engagement.

In our most recent gas access arrangement proposal, Evoenergy prepared gas demand forecasts and indicative expenditure estimates through to 2045 to inform the proposed approach to cost recovery. Through this analysis our community could assess different approaches to capital base recovery against their expectations for an equitable transition pathway, and Evoenergy has demonstrated to the AER and stakeholders the long-term implications of taking inadequate action to recover past investment costs in the 2026–31 period.

This longer-term view of Evoenergy’s gas demand, expenditure forecasts and resultant bill impacts was used both as an engagement tool and to support the regulatory proposal itself. It can reasonably be expected that most, if not all, gas network businesses will prepare similar longer-term, forward-looking analysis to support their own regulatory proposals and demonstrate long-term customer interest in accordance with the NGO. However, to require an annual (or biennial) update of this (and other) analysis as contemplated in the ECA’s Gas Annual Planning Report (GAPR) proposal would impose prescriptive requirements of long-term planning which would come at additional cost but without a clear net customer benefit.

Under the current framework, gas network businesses are required to provide detailed expenditure and demand forecasts to support the access arrangement review process, as well as comply with annual regulatory information notices and reporting requirements under Part 10 of the NGR. These obligations coupled with the material developed and shared by gas network businesses through access arrangement review processes provide sufficient surveillance of the longer-term implications of the energy transition without the additional regulatory costs imposed by additional planning reporting requirements including those contemplated by ECA to be included in the GAPR. Against a shrinking customer base, the regulatory framework and gas network businesses should be making efforts to reduce, rather than add to, the costs to be recovered from those customers who are least able to electrify early (Questions 7 and 8).

b. Regulatory tools to manage unforeseen events or material changes

Expanding regulator discretion to fix or vary access arrangement periods unilaterally undermines the propose-respond model of regulation, reduces investor confidence and assumes that the regulator has greater insight into the risks faced by the network over the regulatory period than the business itself.

As noted in the AEMC's review, within the current framework there exist a number of mechanisms that allow a gas business to respond to material changes or unforeseen events within a regulatory period. Regulators are required to assess these mechanisms within the context of the NGO and RPPs. Changes to the existing tools to manage demand risk and unforeseen events should not be necessary if regulators make decisions using the tools available within the current regulatory framework to allow networks to manage risk commensurate with the level of commercial and regulatory risk they face.

Gas distribution businesses generally fix the access arrangement review submission date five years after the start of the current regulatory period. However, the existing framework provides businesses with flexibility to propose a longer, or shorter period²² to suit their circumstances, including the degree of commercial and regulatory risk. The regulator must approve the proposed period if it is consistent with the NGO and RPPs.²³ If the regulator determines the proposed period to be inconsistent with the NGO and RPPs, the regulator must fix an alternative period. Expanding the regulator's discretion to set access arrangement periods beyond that already provided for under NGR 50 (3) risks undermining the propose-respond model established in the current regulatory framework and assumes that the regulator has greater insight into the risks faced by the network over the regulatory period than the business itself (Question 11).

The NGR also provide gas network businesses with options to vary the access arrangement within a regulatory period to respond to changes in circumstances or unforeseen events, either by specifying a trigger event²⁴ or by seeking a variation during the period.²⁵ Providing the regulator with discretion to reopen or vary an access arrangement review submission date would likewise undermine the regulatory model, materially impact investor confidence, and impose additional regulatory costs for no benefit to customers (Question 12).

On the question of aligning the timing of gas and electricity distribution decisions (Question 11.2), Evoenergy observes that it is unclear the net benefit value this would bring. Importantly both electricity and gas networks report actual demand outcomes to the AER every year through the Regulatory Information Notice / Annual Information Order processes and undertake updates to demand forecasts every year for the purposes of annual tariff setting. Therefore, it is not necessary to align the regulatory period for gas and electricity networks to enable recent trends in demand on the alternate network to be taken into account. Further, for a small dual energy fuel networks such as Evoenergy, aligning regulatory submissions would create significant resourcing challenges and increase regulatory costs to customers across both energy fuels. Therefore, consideration of aligning regulatory review process must consider the cost-benefit trade-off relevant to the circumstances of the network.

²² NGR 50.

²³ NGR 50 (2).

²⁴ NGR 51 (1)(c).

²⁵ NGR 65.