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Attachment 7: Transportation (including metering) reference tariffs

Response to the Australian Energy Regulator's draft decision

ACT and Queanbeyan-Palerang gas network access arrangement 2026–31

Submission to the Australian Energy Regulator

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1. Transportation (including metering) tariff variation mechanism

1.1 Overview

1.1.1 Our initial proposal of a revenue cap TVM

The tariff variation mechanism (TVM) in our access arrangement sets out how prices will vary each year. Historically, our gas network prices have been set using a weighted average price cap (WAPC) TVM.

Price caps expose gas networks to demand forecasting risk (the difference between the forecast set by the regulator and actual demand), which provides an incentive to grow (or minimise declines in) volumes. Such incentives are no longer appropriate for our network. Gas is now the more emissions-intensive energy source in the ACT, and the ACT Government has committed to phase out its use, with decommissioning to commence in the 2035–40 period, as part of the ACT's journey to net zero by 2045.[1]

Accordingly, and informed by extensive customer engagement, our access arrangement proposal included a revenue cap TVM. A revenue cap TVM entirely removes the incentive for us to grow (or minimise declines in) volumes – an incentive we cannot respond to and should not have in this policy context – and, amongst other benefits, promotes economic efficiency by ensuring that customers pay no more or less than the AER determined revenue allowance.[2]

1.1.2 The AER's draft decision to require a hybrid TVM

The AER did not accept our proposal in its draft decision. Instead, the AER's draft decision reflected the position it foreshadowed in its final decision on our reference service proposal,[3] and required that we implement a hybrid TVM.

The AER's reasons for its draft decision are brief and substantially the same as those given for its decision to accept a hybrid TVM in Jemena Gas Network's (JGN) access arrangement for 2025–30. Limited explanation is given as to the AER's consideration of the mandatory TVM factors included in rule 97(3) of the NGR. This makes it difficult for Evoenergy (and other stakeholders) to properly understand and respond to the AER's draft decision.

The AER's primary reason for requiring a hybrid TVM appears to be that it considers a hybrid will best reduce the incentive to grow demand inherent in a price cap form of control, while providing protection to consumers against large price increases if demand falls faster than forecast. The AER was particularly concerned that a revenue cap TVM would result in potential year-on-year tariff volatility.[4]

The AER pointed to the approach it approved for JGN, under which the AER assesses tariffs under the WAPC, except to apply a partial true up of revenue if actual revenues for a year are 5 per cent lower or higher than the AER's allowed revenues due to demand forecasting error. JGN

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

[2] A complete list of reasons is set out in Attachment 9 of our initial access arrangement revision proposal.

[3] AER (2024). Final decision – Evoenergy reference service proposal 2026–31, November, p. 13.

[4] AER (2025). Draft decision – Evoenergy access arrangement proposal 2026–2031 – Attachment 5 Reference services, tariffs and non-tariff components, November, p. 22.

and consumers share the under or over recovery above this threshold on a 50/50 basis. The AER appears to signal that such an approach may also be appropriate for Evoenergy, and capable of acceptance.

The AER proposed to compensate us for jurisdictional charges (that is, ACT Government taxes and levies including the Utilities Network Facilities Tax (UNFT) and Energy Industry Levy (EIL)) in our opex building block on an ex ante forecast basis, with no true up for forecasting errors using the TVM.

1.1.3 Our revised proposal for the TVM

Our revised proposal for the TVM:

- maintains that our access arrangement should be subject to a revenue cap,
- outlines that the AER’s draft decisions contravenes the NGL and NGR because it does not provide us with an opportunity to recover efficient forecast costs and does not provide us with effective incentives to promote economic efficiency in respect of investment in, and operation of, our network, but
- proposes a hybrid TVM, consistent with the AER’s requirement for us to do so, including a lower threshold for the sharing of differences between our actual revenues and the AER's approved revenue allowances, and
- maintains the approach approved by the AER for the current 2021–26 period for jurisdictional charges, under which our UNFT and EIL payments are subject to a true up mechanism under the TVM.

Our revised proposal for a 'narrow' hybrid TVM

A revenue cap TVM is the only appropriate mechanism for our tariffs in the face of declining and uncertain demand, and a legislated target for net zero greenhouse gas emissions by 2045.

We consider that the AER's draft decision is not consistent with the National Gas Objective (NGO) and the revenue and pricing principles, and does not comply with the National Gas Law (NGL) and National Gas Rules (NGR).

The AER's draft decision, which does not approve a revenue cap TVM, requires a hybrid TVM, and indicates we should adopt a JGN style hybrid TVM with a 5 per cent revenue constraint, is contrary to the NGL and NGR. Its stated reasons for the decision are either incorrect or premised on considerations to which the AER is not permitted to have regard.

Given the changed context of demand uncertainty and asymmetric demand forecasting risk, driven by factors outside of Evoenergy’s control, the AER’s proposal will result in a TVM that is not designed to equalise forecast revenue with the revenue allowance set by the AER, contrary to NGR 92(2).

The AER's draft decision does not provide us with an opportunity to recover at least our efficient costs, or with effective incentives to promote economic efficiency with respect to our network. More specifically:

- The NGL and NGR (through the NGO) require the AER to make a decision which will promote economic efficiency with respect to the long term interests of consumers.
- A revenue cap TVM will promote economic efficiency in the long term interests of consumers, including because it:

  - provides us with a reasonable opportunity to recover the AER's approved allowance for our efficient costs, and
  - removes any perverse incentives on us to grow (or minimise declines in) demand.
- Any hybrid TVM will, in our present operating environment likely result in our expected revenue being lower than the AER's allowance for our efficient costs, and will create perverse incentives for us to grow (or minimise declines in) demand.

Further, the AER's draft decision appears to be premised on its finding that a revenue cap TVM will result in greater short term tariff volatility compared with a hybrid TVM. However, this is an irrelevant consideration:

- The NGL and NGR (through the NGO) require the AER to make a decision which will promote economic efficiency with respect to the long term interests of consumers.
- The NGL and NGR do not permit the AER to make a decision that does not promote economic efficiency in the long term interests of consumers on the basis that such a decision will reduce short term price volatility.
- That is, the AER cannot refuse to approve a revenue cap on the basis of short term pricing volatility, and instead adopt a hybrid TVM that does not promote economic efficiency in the long term interests of consumers.

In any event, the AER is incorrect to consider that a revenue cap TVM will result in greater short term tariff volatility than a hybrid TVM, in the context of our network. The AER does not provide any evidence to support this conclusion, with the result that its decision is affected by legal error and invalid. Further, our analysis demonstrates that, in the context of declining demand during the ACT's transition to net zero by 2045, a revenue cap would result in less tariff volatility. Accordingly, the AER's draft decision is contrary to section 28(1)(a) of the NGL and 68B(1)(a) of the NGR, as it is inconsistent with the NGO and the revenue and pricing principles.

We also observe that the deficiencies in the AER's draft decision are heightened by its decisions on our demand forecast and tariff structure.

Nonetheless, as we anticipate that the AER will not accept a revenue cap TVM and the draft decision required us to propose a hybrid TVM, we have developed a hybrid TVM for our revised proposal. While we maintain that a revenue cap is the only appropriate TVM in our circumstances, we have developed a hybrid mechanism that is more appropriate in the context of our network and mitigates the extent of the NGL and NGR non-compliance associated with the JGN style hybrid TVM contemplated by the AER's draft decision.

The hybrid TVM applies a WAPC if actual revenues for a year are 2 per cent higher or lower than the AER's allowance for our efficient costs, and consumers partially share any over or under recovery beyond this threshold on a 50/50 basis, in our access arrangement for the 2026–31 period. We refer to this throughout as a 'narrow' hybrid TVM, as it applies in a narrower range of deviations in actual revenues from AER allowed revenues compared to the JGN TVM.

The lower threshold in our proposed hybrid TVM mitigates, but does not eliminate, the issues with the AER's draft decision identified above. This is because one of the key issues inherent in a hybrid TVM is that our ability to recover the AER's approved allowance for our efficient costs is dependent on the AER's demand forecast being accurate. Under a hybrid model, we bear 100 per cent of the demand forecasting risk up until the specified threshold for the sharing of deviations in actual revenue from the AER's approved allowance. The higher the threshold, the greater demand forecasting risk we bear, and the greater the shortfall in our actual revenue from the AER's approved allowance, and our resultant inability to recover approved efficient costs, where the decline in demand is faster than forecast by the AER.

Given the context of our network and the ACT legislative and policy environment, we face material demand forecasting risk and asymmetric demand forecasting risk. This is recognised by the AER in its draft decision.[5] Accordingly, a lower threshold is appropriate, as it will reduce the impact of demand variations from forecast on our overall revenue, providing us with a better opportunity to recover the AER's approved allowances for our efficient costs, compared to a broader hybrid.

Similarly, the lower threshold will reduce our incentives to grow (or minimise declines in) demand on our network, contrary to the ACT's legislated target to achieve net zero emissions by 2045 and the emissions reduction element of the NGO. While these incentives are not entirely removed where a narrow hybrid TVM of the kind we propose is adopted, as they would be under a revenue cap TVM, they are lesser than under a hybrid TVM with a 5 per cent threshold.

While our community forum’s preferred hybrid TVM design was a 50/50 sharing with no revenue constraint, we have not put this forward in our revised proposal on the anticipation it would not be acceptable to the AER.

Our revised proposal for a true up for UNFT and EIL payments under the TVM

Our revised proposal for the TVM maintains the approach approved by the AER for the current 2021–26 access arrangement period, under which jurisdictional charges are included as category specific costs in our opex forecast, subject to a true up. Our jurisdictional charges include the Utilities (Network Facilities) Tax (UNFT) and the Energy Industry Levy (EIL).

The AER's primary stated reason for requiring the removal of any mechanism in the TVM for us to recover our UNFT and EIL payments in full is that it considers this will create incentives for us to achieve efficiencies in respect of these payments, by incentivising us to work with the ACT Government to minimise the impact of these charges.[6] We note that jurisdictional charges are outside of our control, and set by the ACT Government annually to meet its own-source taxation requirements (see Attachment 5: Operating expenditure for supporting evidence and complementary discussion on the treatment of government taxes and levies).

The AER's draft decision to exclude these costs from our TVM will deny us the opportunity to recover the efficient costs associated with our regulatory obligations to pay jurisdictional charges, without creating any benefits for economic efficiency.

Our unique circumstances warrant a unique approach to the TVM

We recognise that we are at the forefront of the energy transition and there are challenging matters to work through. However, we encourage the AER to – just as it had articulated back in 2021[7] – apply approaches which are cognisant of plausible and foreseeable energy scenarios, be prepared to adjust in the face of new circumstances, and consider applying different regulatory approaches in each jurisdiction. Or in the words of one of our customers:[8]

[5] See, for example, AER (2025). Draft decision Evoenergy (ACT) access arrangement 2026 to 2031 -Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax, November, pp. 53–55.

[6] AER (2025). Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 3, November, pp.19–20.

[7] AER (2021). Regulating gas pipelines under uncertainty, November, p. vii and viii.

[8] Appendix 1.1: Communication Link-Evoenergy community and customer forums-January 2026, p. 32.

'The world is changing, recognise that this is the first jurisdiction to face the challenge of closing a network. Embrace change and recognise that ACT is a small jurisdiction and does not create a meaningful precedent for other future decisions.'

The AER's draft decision requires Evoenergy to adopt a hybrid TVM at a time when there is already heightened uncertainty around the future of gas networks and a credible risk that Evoenergy will not have a reasonable opportunity to recover our efficient costs. In so doing, the AER's draft decision operates to expose Evoenergy to significant risk that we will not recover the AER's approved allowance for our efficient costs (which, as discussed elsewhere in our revised proposal is, by design, insufficient to compensate us for our efficient costs).

HoustonKemp concludes, to the extent that the AER's higher demand forecasts incorporate an upward bias, we can expect to under recover our efficient costs under a hybrid TVM.[9] This is because, under a hybrid TVM, we are not compensated for differences between actual and forecast revenue up to a specified threshold, and even beyond that threshold, we are permitted to recover only a portion of the difference.

There is a heightened probability that the AER will set an incorrect demand forecast, given uncertainty and asymmetric demand forecasting risks. The AER highlights 'the actual speed of gas demand reduction will depend on future developments in government policy, and evolving customer sentiment and behaviour towards electrification'.[10] Given that demand is driven by factors outside of our control, we will bear revenue risk under the hybrid TVM for risk factors that we cannot reasonably manage. The AER's draft decision does not provide compensation for such risks.

The AER's draft decision increases Evoenergy's risk of over or under-recovering jurisdictional charges from customers, and creates risks for customers of paying more or less than needed for safe and reliable gas distribution services, in direct contrast to the preferences of our community[11] and the ACT Government.[12] Under the AER's draft decision, Evoenergy's gas network is to be allocated greater risk than electricity distribution networks, who do not face the same cost recovery challenges, without providing any compensation for those additional regulatory and commercial risks.

In response to the AER's draft decision, our revised proposal can be summed up in the words of a member of our community forum:[13]

'It's time to do something new. Let's be the first jurisdiction to do something different in terms of pricing (revenue cap) and accelerated depreciation. Not liking a revenue cap, just because you [AER] don't think we were well informed is not a valid reason, it needs to be backed with actual evidence as to why it is not beneficial.'

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[9] Houston Kemp (2026). Appendix 3.3 Assessment of the AER's draft decision on depreciation, January, p. 29

[10] AER (2025). Draft Decision – Evoenergy (ACT) access arrangement 2026–31 – Attachment 1, November, p. 17.

[11] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31 – Appendix 1.2 Report of feedback from community forum sessions 1-10, June, pp.42–43 and 44–45.

[12] In its submission on Evoenergy's RSP, the ACT Government stated: 'It is important during the energy transition that gas customers pay no more than is necessary for maintaining the gas network and also that Evoenergy receives sufficient revenue to maintain its operations.' ACT Government (2024). Submission – Evoenergy Reference service proposal, August, p.2.

[13] Appendix 1.1: Communication Link-Evoenergy community and customer forums-January 2026, p. 30.

1.2 The AER’s draft TVM decision

1.2.1 The AER's draft decision to require a hybrid TVM

The AER did not accept our proposal for a revenue cap TVM for our transportation (including metering) reference services. Rather, the AER requires Evoenergy to:[14]

- implement a hybrid approach for our TVM, and
- exclude government taxes, levies and other licence fees from the transportation (including metering) reference service TVM.

The AER observed that WAPC regulation incentivises network service providers (NSPs) to grow the volume of gas carried by their networks, as networks retain any revenue earnt from actual volumes being higher than forecast. Equally, networks incur costs if actual volumes are lower than forecast whereby, they do not recover the efficient revenue allowance set by the AER. The AER consider that WAPC regulation assigns volume risk to networks. Therefore, networks are incentivised to grow (or minimise reduction) in demand. The AER recognise that these incentives are not present under revenue cap regulation, as service providers can earn only their approved revenue.

The AER considers that revenue cap regulation creates risk of year-on-year tariff volatility due to revenue true-ups, while WAPCs provide for relatively stable tariffs. The AER considers revenue cap regulation assigns volume risk to customers.

In the AER's view, a hybrid approach, with elements of both price cap and revenue cap regulation that assigns volume risk to both customers and the NSP:

- reduces the incentive inherent in a pure price cap form of control to encourage gas consumption (aligning with the emissions reduction objective), while providing protection to consumers against large price increases if demand falls faster than forecast,
- avoids creating year-on-year tariff volatility, and
- reflects the changed regulatory context for provision of gas transportation services.

The AER noted a submission from its Consumer Challenge Panel (CCP33) who accepted that our Energy Consumer Reference Council (ECRC) generally supported a move to a revenue cap, but discussed the apparent struggle customers had with understanding the implications of the different TVMs. The AER also questioned the way we engaged with, and presented the suitability of a revenue cap to, our customers.[15]

Although the AER did not specify the exact form of hybrid it proposes should apply, it refers to the hybrid it approved for JGN for the 2025–30 period. The JGN-hybrid is a WAPC approach up to a revenue constraint of 5 per cent, but provides for a partial true up of revenue under or over recovery if actual demand varies from the AER’s final decision demand forecast by more than 5 per cent, and that partial true up is shared between the network and consumers on a 50/50 basis.

[14] AER (2025). Draft decision – Evoenergy access arrangement proposal 2026–2031 – Attachment 5, November, p. 19.

[15] AER (2025). Draft decision: Evoenergy (ACT) access arrangement 2026 to 31 - Overview, November 2025, p viii.

1.2.2 The AER's draft decision to exclude a true-up of jurisdictional charges from the TVM

The AER’s draft decision departed from its current approach to include government taxes, levies and other licence fees as a separate adjustment in the transportation (including metering) reference service TVM. The AER's reasons for its draft decision were that:[16]

- providing a true-up in the TVM effectively funds these costs on a cost-of-service basis, which is inconsistent with the incentive-based framework,
- including government fees and taxes in opex, without any form of adjustment, is consistent with the third revenue and pricing principle, being to promote economic efficiency with respect to the services the service provider provides,
- by providing an incentive to lower costs, the AER's approach helps achieve the NGO, by promoting efficient investment in, and efficient operation and use of, covered gas services for the long-term interests of consumers of covered gas with respect to price, quality, safety, reliability and security of supply of covered gas, and
- cost pass through arrangements are sufficient to deal with material changes in costs associated with government fees and taxes, such as the UNFT and EIL.

1.3 Our response to the AER's draft decision

1.3.1 Decision to impose a hybrid TVM is inconsistent with the NGL and NGR

Overview

We remain of the view that a revenue cap is the only form of TVM that is compliant with law, in our circumstances, for the reasons outlined in our initial proposal. In Evoenergy's operating environment, a revenue cap TVM promotes economic efficiency and the achievement of jurisdictional emission reduction targets, because it:[17]

- ensures that revenues recovered from customers reflect no more and no less than the AER approved allowance for the efficient cost of operating our network,
- removes demand forecasting risk for us and our customers,
- removes perverse incentives to grow (or minimise declines in) demand, and ensures consistency of Evoenergy's incentives with the ACT's legislated emissions target of net zero emissions by 2045 and the emissions reduction element of the NGO,
- provides for consistent regulatory arrangements between gas and electricity energy substitutes for our customers, which will facilitate an efficient energy transition, provide cost-reflective price signals, and enable a total energy bill hedge as energy prices adjust in line with the pace of transition, and

[16] AER (2025). Draft decision- Evoenergy (ACT) access arrangement 2026 to 31 - Attachment 3,3 November, pp 19–20.

[17] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31-Attachment 9, June, pp. 5–6.

- avoids price variability over the short and long term by allowing prices to incrementally adjust to align with consumer preferences using well established regulatory tools such as a rolling unders and overs mechanism.

For these reasons, we maintain that a revenue cap TVM promotes the NGO, and achieves compliance with the NGL and NGR in our circumstances.

By contrast, the AER's draft decision, that our access arrangement should contain a JGN style hybrid TVM, hinders the achievement of the NGO, and is contrary to the NGL and NGR, as:

- any form of hybrid TVM would not provide us with an opportunity to recover at least the AER's approved allowances for our efficient costs, or, thus, with effective incentives to promote economic efficiency with respect to our network, and is, therefore, contrary to the NGL and NGR, and
- a hybrid TVM is not compliant with the provisions of the NGR relating to TVMs.

As a result, the draft decision is contrary to section 28(1)(a) of the NGL and 68B(1)(a) of the NGR, as it is inconsistent with the revenue and pricing principles, and thus, the NGO. That is, the AER’s draft decision, if maintained, is unlawful.

Our revised proposal includes a legal opinion from the Hon John Middleton AM KC, DLA Piper Senior Advisor and former Judge of the Federal Court of Australia and President of the Australian Competition Tribunal (Appendix 3.2). In this legal opinion, the Hon John Middleton AM KC concludes that the AER's draft decisions on the economic lives of our pipeline assets and accelerated depreciation, and the various other components of our 2026–31 access arrangement, including the hybrid TVM, are affected by a number of legal errors, and produce an outcome that unreasonably allocates risk to Evoenergy. This includes the AER’s requirement for a hybrid TVM, instead of Evoenergy's proposed revenue cap, where:

- the recovery of forecast efficient forecast costs is dependent on the accuracy of the AER’s demand forecast, in circumstances where the AER emphasises the uncertainty of future gas demand and the rate of decline due to factors beyond Evoenergy’s control, and
- the extent to which there is upward bias in the AER’s demand forecast, and in the context of asymmetric demand risk, Evoenergy can expect to under recover 100 percent of AER forecast efficient costs up to a 5 per cent variation between actual and forecast demand, and only recover a portion of AER forecast efficient costs (50 per cent) beyond the revenue constraint.

The AER’s assertion that a revenue cap regulation assigns volume risk to customers neglects to consider that:

- Customers hold long term volume risks under the regulatory framework, including between regulatory periods, where fixed network costs are recovered over a declining customer base, and
- an access arrangement may be reopened or the review date brought forward where the demand forecast may be recalibrated.

We note that the AER’s draft decision considered that revenue cap regulation would create risk of year-on-year tariff volatility due to the revenue true-ups, while WAPC regulation provides for relatively stable tariffs.[18] This was one of the AER's key reasons for preferring a hybrid TVM over a revenue cap TVM. However:

- the AER is not authorised by the NGL and NGR to make a decision to apply a hybrid TVM on the basis of short term price impacts, in circumstances where this does not promote economic efficiency in the long term interests of consumers, and
- in any event, the AER is incorrect to conclude that a revenue cap TVM will result in short term tariff volatility.

While the AER recognised Evoenergy's consideration that a revenue cap provides efficient price signals and enables a total energy bill hedge between gas and electricity substitutes,[19] the AER did not consider or acknowledge price smoothing tools that are available for use under a revenue cap (such as a rolling unders and overs account).

The AER did not provide any evidence to support its conclusion that a revenue cap TVM would increase year-on-year tariff variability, in the context of our network operating environment.

Our modelling (outlined below) finds that a revenue cap will deliver *less* price variability, if demand is consistently lower than forecast. Even where demand varies above and below forecast symmetrically, there is no material difference in tariff volatility under a revenue cap TVM versus a hybrid TVM.

A hybrid TVM will not provide an opportunity to recover efficient costs due to asymmetric demand risk

The AER's decision on, and the provisions of, our access arrangement must contribute to the achievement of, and be consistent with, the NGO (section 28(1)(a) NGL and 68B(1)(a) NGR).

As noted in the legal opinion of the Hon John Middleton AM KC, a decision which is inconsistent with the NGL's revenue and pricing principles cannot be a decision which is consistent with the NGO. Accordingly, NGL and NGR compliance requires any decision by the AER to be consistent with the revenue and pricing principles.

Of relevance here is the foundational principle that we should be provided with the opportunity to recover at least our efficient costs. While the regulatory framework does not guarantee recovery of costs, efficient or otherwise, the Australian Competition Tribunal concluded that: [20]

> 'if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs. This is in the context of no adjustment generally being made after the event for changed circumstances.'

Additionally, the NGR require that a TVM be designed to equalise forecast revenue for reference services with the total revenue allocated to reference services (in net present value terms).[21]

[18] AER (2025). Evoenergy (ACT) access arrangement 2026 to 31 Attachment 5, November, p. 22

[19] AER (2025). Evoenergy (ACT) access arrangement 2026 to 31 Attachment 5, November, p. 20

[20] Application by EnergyAustralia and Others [2009] ACompT8 at [77] – [78].

[21] NGR, rules 68B(1)(b) and 92(2).

Historically, price cap TVMs have provided network service providers with an opportunity to recover at least their efficient costs, and have operated to equalise forecast revenue with the revenue requirement set by the AER. This was done on an ex ante basis, with prices set by dividing forecast revenue by forecast demand, where the forecasts represented the best forecast possible in the circumstances.[22] Network service providers' opportunity to recover at least their efficient costs was supported by their incentive and ability to grow gas demand which, historically, operated in the long-term interests of consumers by sharing largely fixed network costs over a higher level of demand.

However, a consequence of an incentive-based framework and ex ante regime is that the revenue allowance, and recovery of an efficient allowance are typically not revisited and adjusted after the fact, regardless of what happens during the regulatory period. If circumstances change, such that the demand forecast set by the AER in its final decision is not accurate, no adjustment is made to reflect the change in circumstances. The gas distributor and customers bear the risk of forecasts being too high or too low.

Historically, there was symmetric demand forecasting risk, driven by factors which could result in higher or lower demand than forecast. Such factors include weather outcomes, the relative movements of electricity and gas prices, appliance development, and differences in a business's effectiveness in encouraging demand (relative to performance embedded in historical trends). There were no factors (e.g. legislative, environmental or other) that resulted in the risk that actual demand would be lower than forecast being greater than the risk it would be higher than forecast (or vice versa).

The symmetric nature of the demand forecasting risk ensured that forecast revenues, in ex-ante expected value terms, were set to equal the revenue requirement decided by the AER.

This is no longer the case. Demand forecasting risk is now asymmetric. That is, assuming an unbiased forecast of demand, there is now a material risk that either government policy or consumer preferences accelerate the currently anticipated decline in demand, resulting in demand being materially lower than forecast. For instance, this could occur because of regulatory interventions to support electrification foreshadowed in the ACT Government's Integrated Energy Plan.[23]

However, the reverse is not true. It is highly unlikely that demand will be materially higher than an unbiased forecast of demand, as we will not be able to connect new customers to grow (or minimise the decline in) demand in the ACT, customers will now have to pay the full cost of their connection upfront in NSW, and customers are unlikely to install new gas appliances given that the ACT Government has announced that it intends for the Evoenergy gas network to be decommissioned.

The asymmetry of demand risk is heightened under the AER's draft decision on Evoenergy's demand forecast, which relies on linear extrapolations of historical trends (see Attachment 2: Demand).

Asymmetric demand risk means that, under a WAPC or hybrid TVM, for every $1 of the AER's approved allowance for our efficient costs, our expected recovery is less than $1. As a result, our forecast revenue is unlikely to equal the revenue requirement set by the AER, on an ex-ante basis or in expectation terms, and we are not provided with the opportunity to recover at least the AER's approved allowance for our efficient costs.

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[22] NGR 74.

[23] ACT Government (2024). Integrated Energy Plan 2024-2030 – Our Pathway to Electrification, June, p. 28.

We show this in Table 1, where we present a simplified example of outturn revenue outcomes across a distribution of demand outcomes and a probability weighted average expected revenue, where the AER's approved allowance for our efficient costs is $100. In this scenario, we assume our reference tariffs were set to recover our AER approved allowance by applying the best possible demand forecast available at the time of the AER's decision on our access arrangement (i.e. the one with the greatest probability of occurrence, being a probability of 30 per cent). However, as demand outcomes are asymmetric, in expectation terms, expected revenue is $96 under a WAPC TVM, which is below the AER's allowed revenue of $100. The JGN hybrid TVM will reduce, but not eliminate this difference, resulting in the ultimate recovery of $97.5, still less than the AER’s allowed revenue. [24]

Table 1 Hypothetical revenue outcomes across demand scenarios

Actual demand	2% higher	As forecast	2% lower	15% lower	Expected revenue
Probability	25%	30%	25%	20%	N/A
AER allowed revenue	100	100	100	100	100
WAPC outturn revenue	110	100	90	80	96
Hybrid adjusted outturn revenue[25]	107.5	100	92.5	87.5	97.5

In its draft decision, the AER states that ‘A hybrid mechanism, such as that implemented by JGN, shares the revenues associated with actual volumes being outside revenue thresholds.’[26]

As shown in Figure 1, the AER’s preferred JGN style hybrid TVM does not equally share the deviation in actual revenue from the AER's allowance for our forecast efficient costs. That is, it does not ensure that the TVM is designed to equalise (in present value terms) forecast revenue with the portion of revenue allocated to reference services.

The area under the curve is the revenue risk that sits with the distributor due to the difference between the demand forecast and actual demand. The area above the curve, and bounded by 100 per cent of the revenue allowance, is the risk that customers hold for paying more or less than the AER's allowance for our efficient costs due to the difference between forecast and outturn demand.

Figure 1 demonstrates that a hybrid TVM substantially replicates the incentive and risk properties of a price cap. That is, over a plausible range of demand outcomes, the distributor faces an incentive to grow (or minimise the decline in) demand contrary to emissions reduction principles under the NGO, where both customers and the distributor substantially bear the risk of the demand forecast being wrong and prices being set at levels that are inefficiently high or low, as they do under a WAPC.

For example, Figure 1 shows the JGN hybrid exactly mirrors a price cap up to a 5 per cent demand driven variance in actual revenues from the AER's revenue allowance (100 per cent revenue risk with the distributor). However, even under a 10 per cent demand variance, around 75 per cent of the total revenue risk still sits with the distributor – that is, the JGN hybrid TVM is

[24] Note expected revenue calculated as a weighted probability of $97.5m = (25% × $107.5m) + (30% × $100.0m) + (25% × $92.5m) + (20% × $87.5m)

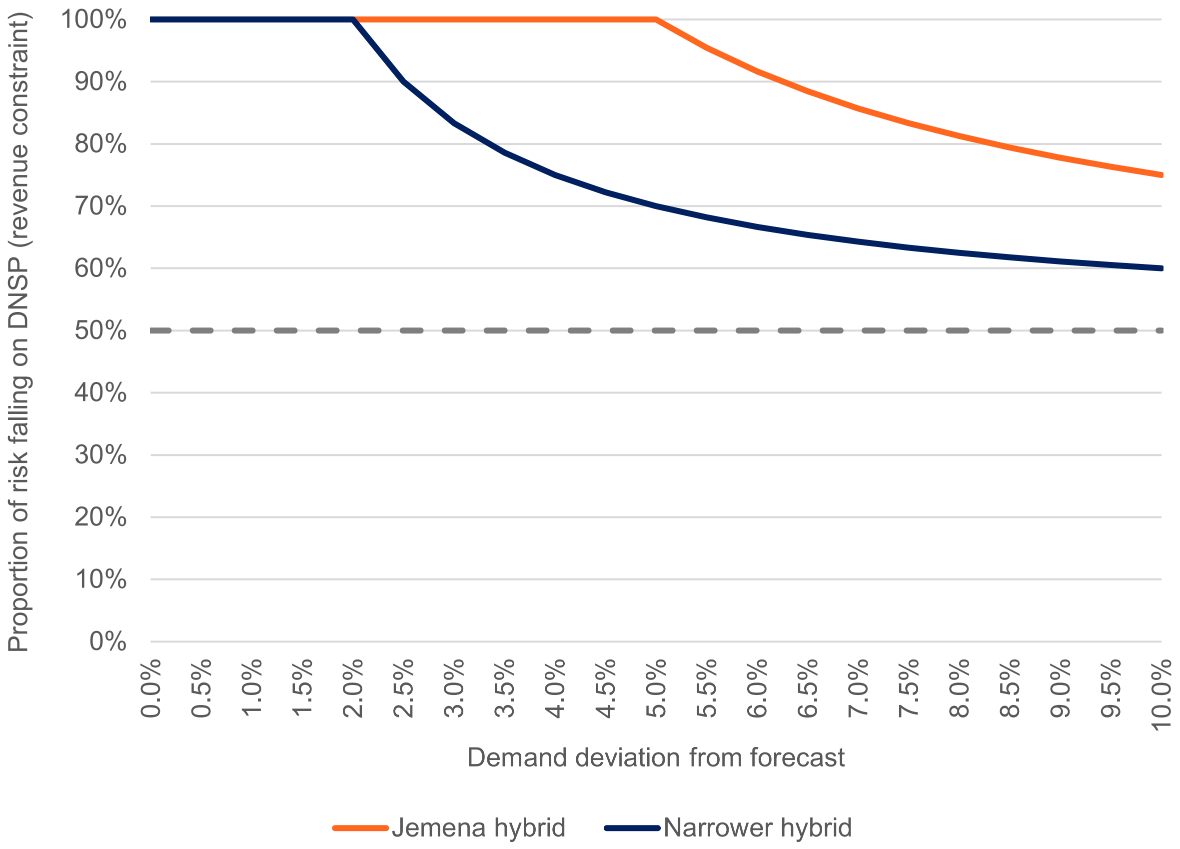
[25] 50:50 sharing, 5% deadband. Ignoring timing differences.

[26] AER (2025). Draft decision – Evoenergy (ACT) access arrangement 2026–31 – Attachment 5, p. 22

substantially a WAPC. Specifically, if demand is 10 per cent higher than forecast, then the network will retain 7.5 per cent more revenue relative to efficient forecast costs, customers pay 7.5 per cent more than the forecast efficient price, with the remaining 2.5 per cent returned to customers. Importantly, there is no level of demand at which the distributor does not face a perverse incentive to grow demand under the AER's preferred hybrid TVM.

In its decision to move from a price cap to a revenue cap for electricity networks, the AER concluded that a hybrid form of control based on a WAPC does not address the inherent problem with the WAPC: 'the WAPC has not incentivised distributors to set efficient prices and is unlikely to do so in the future. Inefficient prices have consequences for allocative efficiency, demand side management and recovery of efficient costs.'[27] As noted above, a hybrid TVM, and to a greater extent a JGN hybrid compared to a narrow hybrid, substantially replicates the incentive properties of a WAPC.

Figure 1 Assymetric exposure to demand forecasting risk



The AER's draft decision appears to recognise demand forecasting risk is asymmetric and driven by factors outside of Evoenergy's control. The AER highlights that a hybrid TVM protects consumers from price increases, if demand is lower than forecast, but does not note that, if demand is higher than forecast, consumers will miss the opportunity for price reductions.

[27] AER (2013). Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy, March, p. 54.

While a hybrid TVM reduces the degree to which ex-ante forecast revenue does not achieve the AER's revenue allowance compared to a WAPC, it does not provide us, on an expectation basis, with an opportunity to recover at least the AER's allowance for our efficient costs.

A revenue cap is a neat solution to the consequences of asymmetric demand forecasting risk. It allows prices to be set on a 'most likely' or 'best' demand forecast (which may be higher than a probability weighted average forecast of demand or at least outturn demand) while still ensuring that we recover at least the AER's allowance for our efficient costs. The demand forecast used under a revenue cap is the most reasonable demand forecast in accordance with the NGR 74(2) because estimates and forecasts are, in effect, updated annually for the most recently available information and approved annually by the AER.

We refer also to HoustonKemp's report, which finds that:[28]

- the AER's proposed hybrid TVM makes Evoenergy's opportunity to recover the AER's approved allowances of efficient costs dependent on the AER's ability to accurately forecast demand for gas,
- Asymmetric demand forecasting risk further contributes to Evoenergy not having a reasonable opportunity to recover at least its efficient costs, and
- this places a great deal of risk on Evoenergy, in circumstances where, as the AER acknowledges, there is a great deal of uncertainty regarding future demand, and the rate of decline rests on factors beyond Evoenergy's control.

Consequently, the AER's draft decision requiring us to apply a hybrid TVM denies us the opportunity to recover the AER's allowance for our efficient costs (which, as noted elsewhere in our revised proposal, undercompensates us for our efficient costs by design). This is contrary to the NGO and the revenue and pricing principles, and, thus, to the NGL and NGR requirements imposed by reference to the NGO.

Additionally, for the reasons outlined above, the AER's proposal will result in a TVM that is not designed to equalise forecast revenue with the revenue allowance set by the AER, contrary to rule 92(2) of the NGR.

A hybrid TVM does not promote economic efficiency

We do not consider that a hybrid TVM promotes economic efficiency (including both productive and allocative efficiency) to the extent that economic efficiency is achieved under a revenue cap, including between energy substitutes, for the reasons outlined in our proposal.

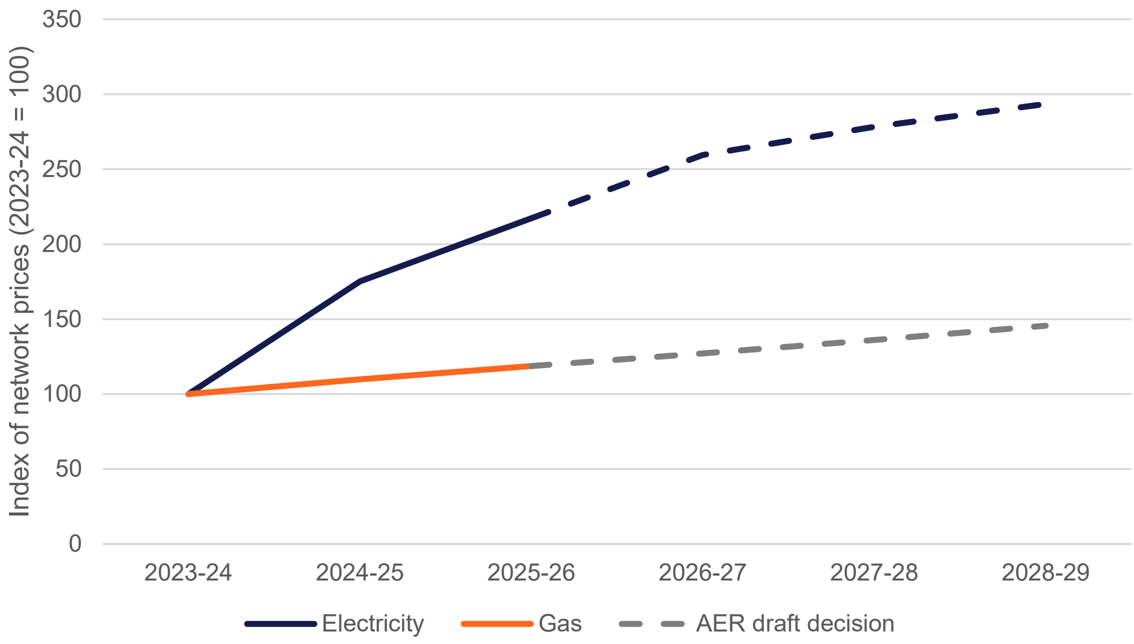
A hybrid, together with an increase in the demand forecast, and without allowing for any flexibility in the change in demand over the period due to factors outside of our control (such as consumer preferences and government policy), cannot achieve the right mix of gas and electricity services. This is explained by the economic principles of cross price elasticity of demand for substitute goods/services and allocative efficiency (where resources are allocated based on consumer preferences).

For the electricity network, which operates under a revenue cap, prices are adjusted for actual demand, so they continue to reflect the recovery of efficient costs approved by the AER and allocative efficiency where price signals reflect consumer preferences (that is, customers' demand). However, if the gas network is subject to a hybrid TVM, it is likely that actual demand will differ from forecasts, and therefore prices (which are not adjusted for actual demand) will not

[28] Houston Kemp (2026). Appendix 3.3 Assessment of the AER's draft decision on depreciation, January, pp. 21, 25, 29.

reflect the recovery of efficient costs approved by the AER. The outcome is a distortion of price signals across the two energy substitutes, which results in customers consuming an economically inefficient mix of gas and electricity services. Moreover, if gas demand is lower than forecast (which is more likely, due to the asymmetric demand risk discussed above), a hybrid TVM results in gas prices that are set too low relative to efficient levels. This would bias customer consumption incentives towards gas, such as shown in Figure 2, which is not only economically inefficient but also contrary to ACT emissions reduction targets and the emissions reduction element of the NGO.

Figure 2 Relative change in gas and electricity network prices



Note: The electricity network charge includes the costs of the Large-scale Feed-In Tariff Scheme which are passed onto energy retailers through the network charge.

Providing an incentive to grow (or minimise declines in) demand contravenes the NGL and NGR

As noted above, the AER's decision on, and the provisions of, our access arrangement must be consistent with the NGO, and thus, the revenue and pricing principles. Of relevance here is the principle that we must be provided with effective incentives to promote economic efficiency in respect of investment in, and operation of, our network for the long term interests of consumers including with respect to the achievement of a participating jurisdiction's targets for greenhouse gas emissions.

Ex ante incentives are at the heart of the Australian regulatory framework. Revenues are set on the basis of forecast cost and demand. This approach is applied to incentivise efficiency by providing rewards for reducing costs or increasing demand relative to the forecast – or applying penalties for cost increases or lower demand.

We note that there is often a misconception that businesses bear ‘volume risk’ in the sense that they share in the pain or gain of demand falling or increasing. This is not correct. Businesses bear volume *forecasting* risk – the risk of differences between forecast demand set by the regulator and outturn demand. Customers also bear volume forecasting risk under a price cap and a hybrid because customers will pay an inefficient price if actual and forecast demand are materially different.

If efficient costs and demand could be forecast with perfect foresight, regulated gas network businesses would always recover exactly their efficient costs – no more and no less (provided decision-making occurred in accordance with the NGL and NGR). The creation of forecasting risk is intended to create incentives for efficiency. Risk is created where:

1. Businesses have some degree of control over costs or demand, in order to create an incentive for them to efficiently incur costs and manage demand. This explains why most regulators subject controllable costs to the operation of incentive schemes (but adopt a cost-of-service approach or true-up mechanism for costs outside of their control).
2. The creation of incentives for efficiency delivers consumer benefits, e.g. reducing expenditure or growing demand reduces average unit costs.

Both conditions must be met for the creation of risk to promote economic efficiency for the long term interests of consumers. Otherwise, the incentives will at best serve no purpose and at worst undermine long term consumer interests. Accordingly, where these conditions are not met regulators apply ex-post mechanisms. This ensures that businesses recover their efficient costs and consumers pay no more than necessary.[29]

We note that in our circumstances:

- We no longer have any reasonable control or influence over demand (as shown in Table 2), and
- If we could control or influence demand, doing so would be contrary to the emissions reduction component of the NGO, given that the ACT has a legislated target to achieve net zero emissions by 2045 and will achieve this via electrification, and the phasing out of gas and cessation of operation of our gas network.[30]

Imposing a hybrid TVM creates demand forecasting risk (although to a smaller extent than a WAPC), and, in turn, an incentive to grow (or minimise declines in) demand. However, as we cannot reasonably, and should not be incentivised to, respond to this risk, this just creates the risk of arbitrary windfall gains and losses without providing any efficiency or consumer benefits.[31] This is contrary to the NGO and the revenue and pricing principles.

[29] We note that importance of incentives and complementary measures was identified by Stephen Lloyd SC when he considered the AER's proposal to introduce a capital expenditure sharing scheme in the Rules against the National Electricity Objective. See Stephen Lloyd SC, Memorandum of Advice, In the matter of the Australian Energy Regulator's Rule Change Requests to the Australian Energy Markey Commission Concerning Chapters 6, 6A, 10 and 11 of the National Electricity Rules and art 9 of the National Gas Rules 2008, September 2011, paragraph 37.

[30] ACT Government (2024). The Integrated Energy Plan 2024-2030 – Our Pathway to Electrification, June, pp.18-19.

[31] We acknowledge that this demand risk is limited by NGR 65, which allows us to apply to vary the access arrangement and effectively shorten the regulatory period. While this mechanism is available, we do not consider that this is the most efficient mechanism to address material forecasting error.

Table 2 Assessment of Evoenergy's historical and current demand levers

Levers	Historically	Now
Accurate demand forecast	Demand forecasts able to be prepared based on historical relationships between weather, consumption, and connections. Forecasts ultimately set by the AER.	Forecast must take into account changes in consumer preferences and government policies, which are not included in historical data. Forecasts ultimately set by the AER.
Tariffs	Ability to set prices to encourage greater usage from existing customers.	AER requires tariffs to be flattened to discourage gas usage.
New connections	Ability to encourage new connections in growth areas. Connection charges limited by a revenue cost test.	Ban on new gas connections (except in limited circumstances) in the ACT and a change to require customers to pay cost-reflective upfront connection charges (AEMC rule change).
Marketing campaigns	Marketing, including appliance incentives, to encourage connection to the network as well as the installation of new appliances.	Marketing to encourage gas use and new gas connections would directly contradict the ban on new gas connections and ACT Government policy on emissions reductions and electrification.
Emissions intensity	Natural gas had a lower emissions intensity than grid electricity.	Gas is now a higher emissions fuel, given that the ACT has achieved net-zero for electricity usage.

The deficiencies in the AER's TVM decision are heightened by its draft decisions on our demand forecasts and tariff structure

Baringa concludes that there are several issues with the demand forecasts adopted by the AER. Specifically, that the AER's forecasts overstate future gas demand due to the reliance on historical data and the starting point for the linear trend – that is, Frontier Economics does not sufficiently take partial electrification into account, and their results are not aligned with historic data on average consumption per customer.[32]

HoustonKemp's report finds that, the risks arising from the draft decision on the TVM are heightened by the AER's demand forecasts, which work to exacerbate the risk that the TVM will act to prevent us from recovering our efficient costs.[33] To the extent that the AER's demand forecasts incorporate an upward bias, this will preclude our ability to recover our efficient costs. This is because, under the volume risk sharing arrangement in the draft decision, Evoenergy will not be compensated for differences between actual and forecast revenue up to a specified threshold and, even beyond that threshold, will be permitted to recover only a proportion of the difference.[34]

[32] Barringa (2026). Appendix 2.4: Baringa review of Evoenergy's gas demand forecasts, January, pp. 20–23.
[33] Houston Kemp (2026). Appendix 3.3 Assessment of the AER's draft decision on depreciation, January, pp. 22 and 25.
[34] Houston Kemp (2026). Appendix 3.3 Assessment of the AER's draft decision on depreciation, January

Additionally, demand forecasts are uncertain. In its draft decision, the AER considered the actual rate of demand decline to be uncertain and that ‘The actual speed of gas demand reduction will depend on future developments in government policy, and evolving consumer sentiment and behaviour towards electrification.’[35] Despite the AER’s consideration that demand is uncertain, the draft decision includes a demand forecast based on historical data that does not account for likely changes in policy to accelerate electrification, changing customer preferences, and the aging stock of gas appliances connected to Evoenergy’s gas network.

HoustonKemp finds that the AER’s draft decision leaves Evoenergy’s opportunity to recover at least its efficient costs dependent on its ability to accurately forecast demand for gas, which the AER acknowledges is uncertain and can be affected significantly by factors beyond Evoenergy’s control’.[36] Asymmetric demand forecast risk, due to the likelihood of exogenous downwards shocks in demand, relative to the demand forecast are more likely than upwards shocks to demand, further contributes to Evoenergy not having a reasonable opportunity to recover its efficient costs.[37] The AER's demand forecast works with the assignment of volume risk under the TVM to further increase the risk that Evoenergy will under-recover its efficient costs.

HoustonKemp also observes that the AER's draft decision requiring that we flatten our tariff structures can be expected to increase the effect on our actual revenue of any differences between forecast and actual demand for gas.[38] This is discussed further in section 2.3.1.

Tariff volatility does not provide a permissible basis for the AER's draft decision to require a hybrid TVM

The reasons for the AER's decision to decline a revenue cap TVM are brief, but the key stated reason appears to be the risk of year-on-year tariff volatility due to revenue true-ups. We understand the AER to be referring to year-on-year tariff volatility in the short term. The AER claims that a hybrid TVM will provide protection to consumers against large price increases.

Under the NGL, the AER's access arrangement decision must be made in a manner that will or is likely to contribute to the NGO (section 28(1)(a)). Additionally, the NGR requires that the provisions of our access arrangement be consistent with the NGO (rule 68B(1)(a)).

In short, the NGO is concerned with the **long term interests** of consumers. It recognises that the long term interests of consumers will be served by the promotion of economic efficiency with respect to the services provided by a service provider, and the network operated by the service provider. The long term interest of consumers will be served by a network service provider having the opportunity to recover at least its efficient costs, and facing effective incentives with respect to the operation of, and investment in, its network. Short term price volatility and consumers' interest in lower short term prices are of no relevance to the NGO and do not provide a lawful basis for the AER's draft decision to require us to apply a hybrid TVM.

For the reasons already discussed, a revenue cap TVM will promote economic efficiency, including by providing us with the opportunity to recover at least the AER's approved allowances for our efficient costs, and effective incentives with respect to the operation of our network,

[35] AER (2025). Draft decision Evoenergy (ACT) access arrangement 2026 to 2031Attachment 1, November, p. 54

[36] Houston Kemp (2026). Appendix 3.3 Assessment of the AER’s draft decision on depreciation, January, p. 33

[37] Houston Kemp (2026). Appendix 3.3 Assessment of the AER’s draft decision on depreciation, January, p. 29

[38] Houston Kemp (2026). Appendix 3.3 Assessment of the AER’s draft decision on depreciation, January, p. 25

whereas a hybrid TVM will not do so. It follows that the AER cannot refuse to approve a revenue cap TVM on the basis of short term price impacts.

Accordingly, the AER's decision to not accept a revenue cap, on the basis of short term price impacts, is inconsistent with the NGO and the revenue and pricing principles. As a result, the AER's decision contravenes section 28(1)(a) of the NGL and 68B(1)(a) of the NGR.

In any event, the AER's finding that a revenue cap TVM would result in greater tariff volatility in the circumstances of our network is incorrect and invalid. The AER does not provide any evidence to support its conclusion. We refer to the legal opinion of the Hon John Middleton AM KC, in which he observes that it is well established that a decision will be made invalidly if the decision maker does not provide any evidence to support its decision.

The AER did not engage with our explanation of the mechanisms that minimise price variability under a revenue cap, such as a rolling unders and overs account, annual updates of demand forecasts, and adopting the same form of control for electricity and gas substitutes.[39]

Given the AER's desire to select a TVM based on its implications for tariff volatility, we have modelled the price impact of each hybrid option, as well as a revenue cap.[40] This modelling demonstrates that there is no material difference between a revenue and hybrid TVM in respect of tariff volatility.

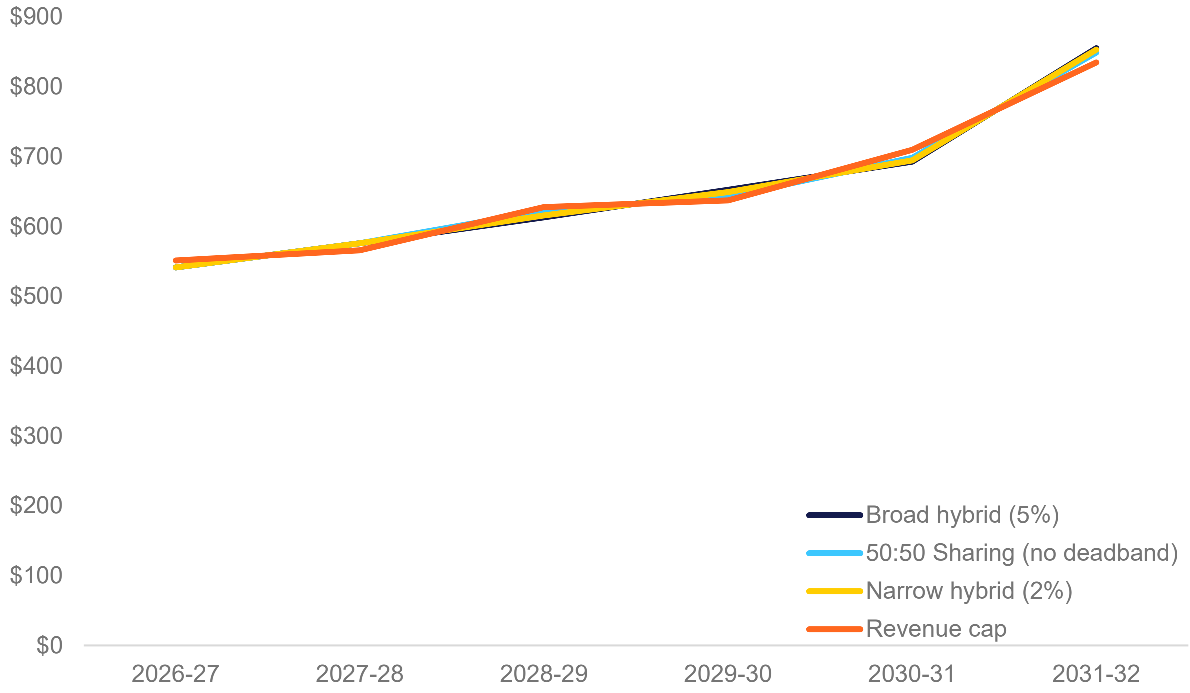
The first scenario we considered was symmetric variations of outturn demand from forecast demand. This scenario represents the historical case, where we were subject to symmetric forces which may have increased or reduced outturn demand relative to forecast demand. In this scenario, demand is 3 per cent higher and lower than forecast.[41] The results are shown in Figure 3.

[39] See Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, Attachment 9, June, pp. 34-38.

[40] Scenarios are all based on revenue and forecast included in the AER's draft decision. In the revenue cap scenario, the quantities used to set prices are based on 20 per cent of the volumes in the AER's draft decision and 80 per cent based on actual. This reflects that we will be able to produce more accurate forecasts throughout the regulatory period, but some forecasting error will remain.

[41] Specifically, down by 3 per cent in 2027–28, up by 3 per cent in 2028–29, and down by 3 per cent again in 2029–30 relative to a forecast of demand. Revenue variations in 2030–31 would not be adjusted for until 2032–33 given the t+2 lagged nature of adjustments for when actual information is available.

Figure 3 Average VI tariff network bills under each hybrid TVM option ($nominal) – symmetric demand variation scenario



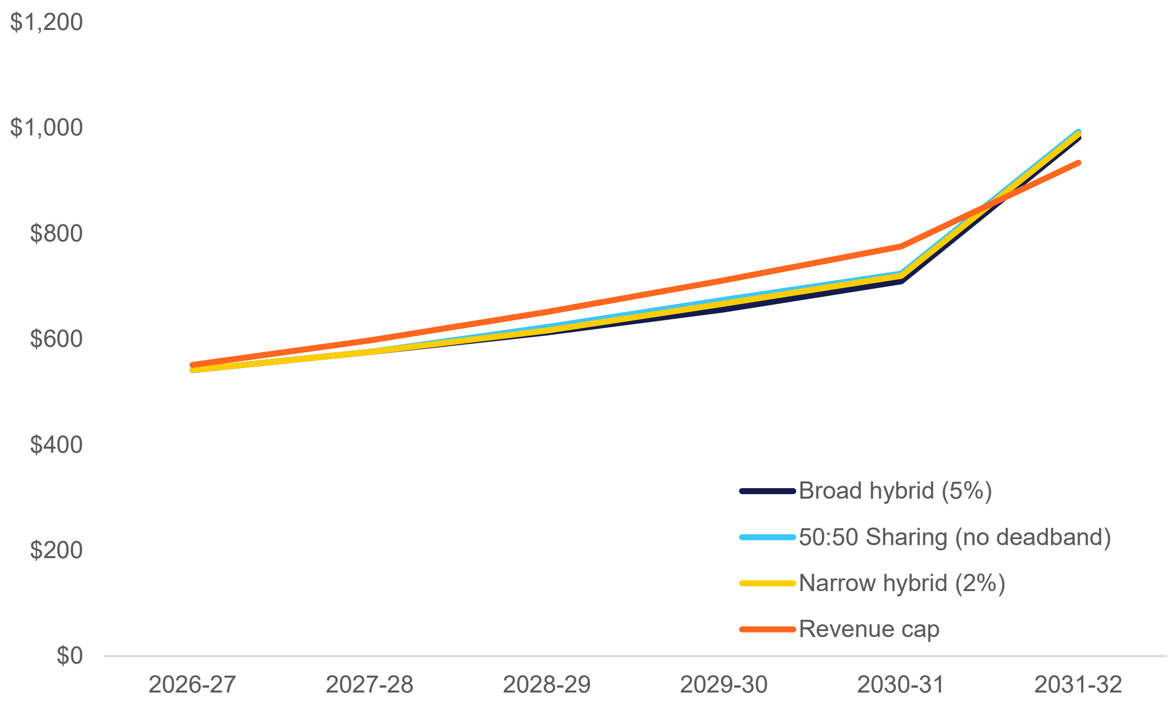
While we find that the wider is the revenue constraint associated with a hybrid TVM, the lower is the tariff volatility, the overall impact is very small. The impact would be even smaller at the retail bill level, given the network component represents less than 30 per cent of the total retail bill. Between the broad and narrow hybrid TVMs, the difference in 2030–31 average VI bills are $1.82. This amounts to about 0.26 per cent of average network bills or about 0.08 per cent of retail bills.[42]

We also note that, although a revenue cap does result in more tariff volatility than the hybrid TVMs, as theory suggests, the impact is not material.

In the second set of scenarios, we consider demand declining 3 per cent faster than forecast in each year. This represents the credible case where the electrification of gas occurs faster than forecast. These results are shown in Figure 4.

[42] On the basis that our network bills make up 30 per cent of the retail bill.

Figure 4 Average VI network bills under each TVM option ($nominal) – declining demand scenario



While the difference in bill outcomes is larger than in the first scenario, the difference between the hybrid TVM options remains very small. The difference between average VI bills in 2030–31 is $10.35 between the broad and narrow hybrid TVMs. This works out to be 1.46 per cent of our network bill or about 0.44 per cent of retail bills.[43]

We note that prices increase in 2031–32 in this scenario. This occurs due to the unavoidable economic reality of price increases with largely fixed costs and reduced volumes. The hybrid TVM options result in prices temporarily decoupling from the AER's approved allowances for our efficient costs. However, this only occurs for a short period – until the end of the access arrangement period or earlier if we lodge an early application to vary the access arrangement, as allowed under NGR 65.

In this scenario, the revenue cap TVM produces less tariff volatility, both within period and between periods. This is because a revenue cap, in effect, allows the demand forecast to be adjusted ensuring that revenues do not significantly diverge from the AER's approved allowances for our efficient costs.

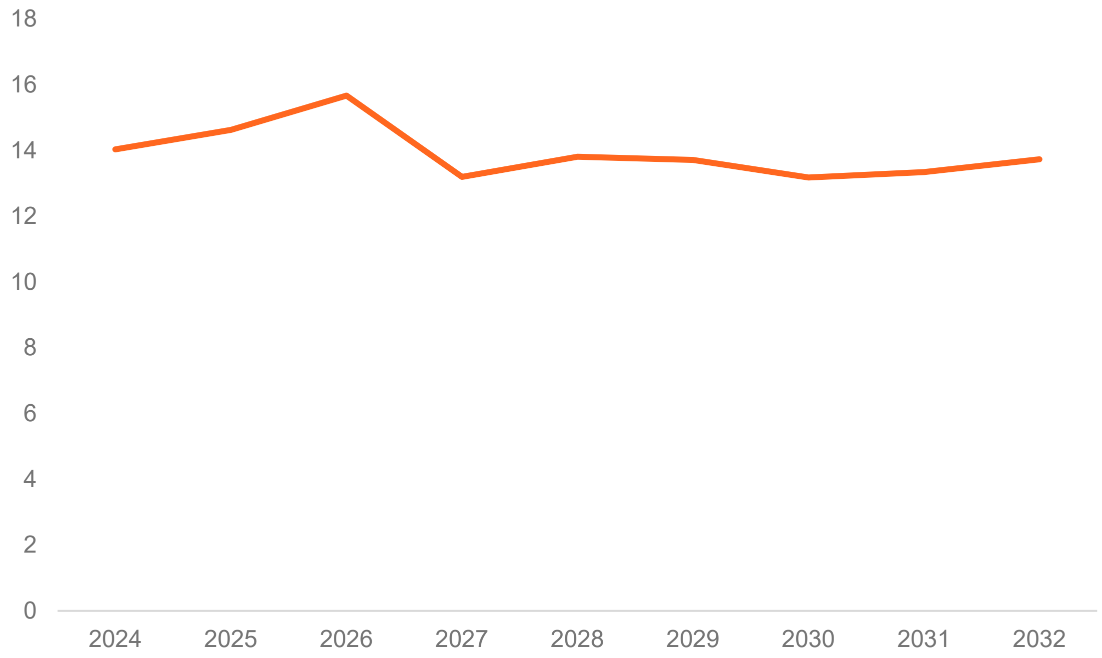
We note that the biggest component of the retail bill is the wholesale gas price, which makes up about 35 per cent of the bill – and recently has been very volatile.[44] While ACIL Allen is forecasting prices to be more stable, the movements are still likely to overshadow any volatility in the network component of the bill. Figure 5 shows forecast wholesale gas prices. These prices are expected to increase by 7.2 per cent in 2026, before falling by 15.8 per cent in 2027 and then rising again by 4.6 per cent.[45]

[43] As out network bill makes up 30 per cent of the retail bill.

[44] See the average daily ex ante gas prices by quarter for each STTM hub, reported by the AER here.

[45] Evoenergy analysis based on AEMO Gas Statement of Opportunities 2025. The step change forecast was developed by ACIL Allen, available at: 2024 Price forecast data files.

Figure 5 Forecast wholesale gas price movements ($/GJ, Nominal)



Source: ACIL Allen's forecast wholesale gas prices, used in the 2025 GSOO

Overall, our analysis finds that there is no material difference in tariff volatility across each TVM option. Further, in the case of a sustained decline in volumes relative to the forecast, the revenue cap TVM provides the least tariff volatility.

Further, we consider that the AER is incorrect to conclude that a hybrid TVM will protect consumers against large price increases, in contrast to a revenue TVM.

While we understand the AER's desire to avoid tariff volatility and protect customers from large price increases – a TVM cannot deliver these outcomes. No TVM can change the economic reality that, with largely fixed costs, falling volumes mean that prices must increase.

At most, a hybrid TVM will delay price adjustments at the cost of larger price shocks in the future and overall, greater tariff volatility. This approach does not promote economic efficiency and is not in the long term interests of customers.

If demand is materially lower than forecast and a revenue cap is not in place, we will be required to apply to vary the access arrangement (NGR 65), to ensure that we have an opportunity to recover our efficient costs (or, at least, to mitigate the extent to which we are denied an opportunity to do so). This would result in unnecessary administrative costs for the AER, customers, stakeholders and us, which could easily be avoided through the implementation of a revenue cap.[46]

With a reasonable probability of accelerating an access arrangement variation, a hybrid cannot protect customers from price increases and, contrary to the AER's intent, results in asymmetric outcomes for consumers. While we will be protected from larger than forecast reductions in demand, customers will be exposed to higher than necessary prices in the unlikely case where demand is higher than forecast. This is because – as the AER has previously identified – we

[46] A factor the AER must have regard to consistent with Rule 97(3)(b).

have the option to apply to vary the access arrangement (if demand is lower than forecast) while customers do not (in the case that demand is higher than forecast).[47]

In contrast to a hybrid, a revenue cap would *ensure* symmetric responses to large deviations in demand.

1.3.2 Decision to impose a hybrid TVM does not account for jurisdictional circumstances

While a revenue cap best accounts for economic efficiency in our unique regulatory context, a narrow hybrid will better reflect our circumstances relative to a broad hybrid. While a broader hybrid TVM may have been appropriate for JGN, it is not appropriate for Evoenergy. The same TVM, as what seems to be suggested in the AER's draft decision, does not account for differences in legislated emission reduction targets between the ACT and NSW, jurisdictional government policy, and differences in customer characteristics and consumer preferences.

The draft decision notes:[48]

> 'We [AER] also consider a hybrid tariff variation mechanism reflects the changed regulatory context for provision of gas transportation services. The NGO now incorporates an emissions reduction element.'

As the AER made similar comments in its final decision for JGN and draft decision for AGN SA[49], we understand that by 'changed regulatory context', the AER means the introduction of an emissions reduction objective in the NGO (which we consider in section 1.2). While we agree that this is a substantial change, it is not the only change and provides an incomplete picture.

We note the AER's view:[50]

> 'As discussed in Appendix B, the policy settings to transition away from the use of natural gas in the ACT has progressed further since the 2021–26 review and is at a more advanced stage compared to Victoria and NSW.'

In addition to this change in the NGO, the ACT is facing several jurisdictional specific regulatory changes, which are not applicable to other networks. In particular:

- The ACT has a net-zero target of 2045 (NSW and SA have 2050 net zero targets), with legislated interim emission reduction targets.[51]
- The ACT will decarbonise through an electrification pathway. This will involve the phase out and decommissioning of our gas network.[52] This contrasts with other jurisdictions

[47] AER (2023). Review of gas distribution network reference tariff variation mechanism and declining block tariffs, October, p.7.

[48] AER (2025). Draft decision-Evoenergy (ACT) access arrangement 2026 to 31, Attachment 5, November, p 22.

[49] AER (2024). Draft decision-Jemena Gas Network access arrangement 2025 to 2030 - Attachment 10, November, p. 5; AER (2025). Draft decision-Australian Gas Networks (SA) access arrangement 2026 to 2031, Attachment 5, November, p. 17.

[50] AER (2025). Draft decision Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax, November, p. 17

[51] AEMC (2025). Emissions targets statement under the national energy laws, September, p. 1.

[52] ACT Government (2024), The Integrated Energy Plan 2024-2030 – Our Pathway to Electrification, June, pp. 4, 10 and 17.

which have not set out an electrification pathway and have introduced or are considering policies to increase the availability of renewable gas such as NSW[53] and Victoria.[54]

- New gas connections have been banned in the ACT, but not in NSW or SA.

While the AER considers that a move from a WAPC to a hybrid TVM reflects 'changed regulatory conditions' for emission reduction targets, the JGN style hybrid TVM suitable to the NSW context does not reflect the operating context of Evoenergy, and is not appropriate for our network.

The price cap nature of the hybrid TVM means that our ability to recover the AER's approved allowance for our efficient costs is dependent on the AER's forecasts being accurate.[55] This is noted by HoustonKemp in its report (Appendix 3.3). We bear 100 per cent of the demand forecasting risk up to the revenue sharing threshold. Demand forecasting risk is materially higher in the ACT compared to NSW, and, as such, a 5 per cent revenue constraint threshold places an unreasonable level of risk on us. This view is also held by the Hon John Middleton AM KC (Appendix 3.2). The reasons why demand forecasting risk is higher in Evoenergy's context, compared to JGN, are shown in Table 3. In Evoenergy's unique context, there is a higher likelihood of material difference between forecast and actual demand.

Table 3 Higher demand forecasting risk for Evoenergy compared to Jemena

	Evoenergy	**Jemena**
Pace of change	Fast, unprecedented, happening now • Customer numbers is decreasing • Consumption per customer is decreasing • 65% of customers plan to cancel gas supply in 10 years[56] • Forecast demand: consumption decreases by 23%, customer numbers decrease by 25% forecast[57]	Slow and steady, reflecting historic trends • Customer numbers are increasing • 34% of customers plan to cancel gas supply in 10 years[58] • Forecast demand: residential consumption decreases by 2.9%, residential customer numbers increase by 0.2%[59]
Driver of change	• Strong policy, including legislated net zero target	• No clear policy and lower customer motivation. Only 47% of NSW households think reducing gas consumption is

[53] As part of the NSW Renewable Fuel Strategy, NSW will expand the Renewable Fuel Scheme to support biomethane. This scheme will introduce a hydrogen and biomethane target of 8PJ by 2038. NSW Government (2025). NSW Renewable Fuel Strategy, November, p. 43.

[54] The Victorian Government has announced they will legislate an Industrial Renewable Gas Guarantee with the goal of reaching 4.5 PJs of renewable gas by 2035. (Victoria Government (2024). Victoria charts path for renewable gas industry, December).

[55] Evoenergy (2025). Attachment 9-Tariff variation mechanism, June, pp. 28-29.

[56] Energy Consumers Australia (2025). How households use gas and their attitudes towards electrification, p. 9.

[57] Evoenergy (2026). Attachment 2: Demand, January, p. 14.

[58] Energy Consumers Australia (2025). How households use gas and their attitudes towards electrification, p. 9.

[59] AER (2025). Final decision-Jemena access arrangement 2025–30 – Attachment 12, May, p. 2.

	Evoenergy	Jemena
	• Ban on new connections,[60] clear policy direction and financial support[61] • Gas network decommissioning from 2035 • Potential for changes to policy measures following 2027 IEP review[62] • High customer motivation – 64% of ACT households think reducing gas consumption is quite or extremely important for reducing emissions[63]	quite or extremely important for reducing emissions[64] • No connections ban and minimal policy direction
Load predictability and stability	• Low load predictability & stability • Only 17% industrial base load (inclusive of our large commercial customers). 59% residential load with technically feasible solution for most customers, and less costly to transition[65] • 49% of households have gas space heating, many of whom also have an electric heating option[66] • July load 5X January load. High seasonal and weather sensitive load, reflecting cooler winter months[67]	• High load predictability & stability • 53% industrial load, providing stable base load, with high transition cost and potentially no technically feasible solution[68] • 27% of households use gas space heating[69] • July load only 2X January load. Flatter seasonal profile, less weather sensitive, reflects warmer winters and industrial base[70]
Forecast method reflects context	• Historic trends no longer sufficient to predict future[71] • No relevant precedent to predict pace of change	• Standard method, where historic trends and econometric models are good predictors of the future with minor adjustments

[60] ACT Government. Climate Change and Greenhouse Gas Reduction Regulation 2011, Div 2.2.

[61] The ACT government has initiated a range of actions to financially support electrification, especially that of ‘priority households’. (ACT Government (2024). The Integrated Energy Plan 2024–2030: Our pathway to electrification, pp. 29-31).

[62] ACT Government (2024). The Integrated Energy Plan 2024–2030: Our pathway to electrification, p. 13.

[63] Energy Consumers Australia (2025). How households use gas and their attitudes towards electrification, p. 8.

[64] Energy Consumers Australia (2025). How households use gas and their attitudes towards electrification, p. 8.

[65] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31,– Attachment 2, June, p. 14.

[66] Energy Consumers Australia (2025). How households use gas and their attitudes towards electrification, p. 5.

[67] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, – Attachment 2, June, p. 14.

[68] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, – Attachment 2, June, p. 14.

[69] Energy Consumers Australia (2025). How households use gas and their attitudes towards electrification, p. 5.

[70] Specifically, Evoenergy’s network usage in July is 5 times that of January, and JGN’s network usage in July is 2 times that of January. Data is based on information from Jemena.

[71] Evoenergy (2026). Revised access arrangement proposal 2026–31 – Attachment 2 Demand, January.

	Evoenergy	Jemena
	• Customer research and policy direction underpin forecast • Forecast is based on stock and age of gas appliances owned by Evoenergy's customers[72] • No AEMO GSOO forecast available for ACT	• Outcomes broadly align to AEMO GSOO forecast for NSW
Risk mitigation	• Very few tools • Ban on new connections[73] • Single tariff covering 99.9% of customers – flatter tariff structure from 4 to 2 consumption blocks for residential and commercial VI tariff customers further reduces revenue risk mitigation options • Growing or retaining customers/consumption is contrary to policy	• Usual tools • No connections ban • The AER's final decision for Jemena is to have 8 total blocks for residential and commercial VI tariff customers,[74] allowing for greater flexibility to mitigate demand risk • No policy against growing gas customers/consumption

We note that jurisdictional differences have previously been recognised by the AER, in making its final decision for JGN, where it noted that there is no gas substitution roadmap in NSW and no statewide ban on new gas connections. Specifically, the AER considered that 'JGN's new hybrid tariff variation mechanism is an additional mechanism to manage demand uncertainty, both for JGN and its customers.'[75]

The AER's draft decision for AGN's SA network recognises that the SA policy environment is different to other jurisdictions, approving $8 million of investments related to renewable gas adaption, and that this environment suggests that the gas network is expected to play a continuing role in the transition to net zero.[76] The AER has made no such allowance for the unique regulatory context in the ACT in making its TVM draft decision.

Customers told us that they considered that the AER has not recognised the unique circumstances of the ACT, noting that:[77]

> *'Is the regulator treating ACT like the other states and not looking at ACT specific policy?'*
>
> *'It just seems like they're totally ignoring the ACT, as a unique case, and just looking at what they're doing in every other state.'*
>
> *'It does not seem to have considered what the ACT position is towards going zero use of Gas.'*

Together, these ACT-specific factors mean we are uniquely exposed to higher levels of asymmetric demand forecasting risk, have a lower ability to control or influence demand, and that

[72] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, Appendix 2.2.

[73] ACT Government. Climate Change and Greenhouse Gas Reduction Regulation 2011, Div 2.2.

[74] AER (2025). Final decision-Jemena access arrangement proposal 2025–30 – Overview, May, pp. 40-41.

[75] AER (2025). Final decision-Jemena access arrangement proposal 2025–30 – Overview,, May, p. viii-ix

[76] AER (2025) Draft decision-Australian Gas Networks (SA) access arrangement 2026 to 2031, Attachment 5, November, November, pp. v, vii and 4.

[77] Appendix 1.1: Communication Link-Evoenergy community and customer forums-January 2026 pp. 26-27.

slowing down reductions in gas demand has the highest cost in terms of forgone emissions reduction.

The AER's draft decision does not account for jurisdictional-specific considerations, which reflects a shift from its previous decision to "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".[78]

As such, as part of the AEMC review on Gas Networks in Transition, Evoenergy submitted that amendments to the NGR requiring the AER to consider jurisdictional context 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' circumstances.[79]

1.3.3 Decision to exclude jurisdictional charge true-up from TVM is inconsistent with the NGL and NGR

Overview

As discussed in section 1.2.2, the AER's draft decision was to include UNFT and EIL payments as an opex step change and exclude any true-up for errors in forecasting those payments from the TVM. The AER's reasons for this were that:[80]

- providing a true-up in the TVM effectively funds these costs on a cost-of-service basis, which is inconsistent with the incentive-based framework,
- including government fees and taxes in opex, without any form of adjustment, is consistent with the third revenue and pricing principle, being to promote economic efficiency with respect to the services the service provider provides,
- by providing an incentive to lower costs, the AER's approach helps achieve the NGO, by promoting efficient investment in, and efficient operation and use of, covered gas services for the long-term interests of consumers of covered gas with respect to price, quality, safety, reliability and security of supply of covered gas, and
- cost pass through arrangements are sufficient to deal with material changes in costs associated with government fees and taxes such as UNFT and EIL.

The AER's draft decision is not compliant with the NGL and NGR, including because it:

- does not provide effective incentives to promote economic efficiency, and
- does not appear to have been made with regard to the criteria in rule 97(3) of the NGR.

While the AER notes that it has had regard to these factors in making its decision on our TVM, it does not provide any specific discussion of its consideration of these factors with respect to its decision to exclude from the TVM any true-up for forecasting errors for UNFT and EIL payments.

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

[79] Evoenergy (2025). Submission to the AEMC's gas networks in transition consultation paper (BRC0082), October, p.7.

[80] AER (2025)., , Draft decision – Evoenergy (ACT) access arrangement 2026–31-Attachment 3, November, pp 19–20.

Additionally, the AER's decision:

- is incorrect to conclude that the treatment of these costs under our current access arrangement is inconsistent with the NGL and NGR incentives based regulatory regime, and
- is inconsistent with the scheme and intent of NGR's provision for the inclusion of a pass through mechanism in a TVM.

Decision to exclude UNFT and EIL true up does not promote economic efficiency

The AER's draft decision is not compliant with the NGL and NGR, as it does not provide effective incentives to promote economic efficiency. HoustonKemp concludes that the AER's draft decision on jurisdictional charges (including the UNFT and EIL) 'is grounded in a flawed rationale and is not supported, as the AER suggests, by the revenue and pricing principle to provide effective incentives to improve economic efficiency.'[81]

National Gas Rules TVM factors

NGR 97(3) requires the AER to have regard to the following factors when deciding whether a particular TVM is appropriate to a particular access arrangement:

(a) the need for efficient tariff structures,

(b) the possible effects of the TVM on administrative costs of the AER, the service provider and users or potential users,

(c) the regulatory arrangements (if any) applicable to the relevant reference services before commencement of the proposed TVM,

(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction),

(e) the risk sharing arrangements implicit in the access arrangement, and

(f) any other relevant factor.

The AER notes, at the beginning of its decision on our TVM, that it has had regard to these factors, and their implications for natural gas consumers, potential users, Evoenergy and other stakeholders.[82] However, the AER does not provide any further detail in its consideration of those factors, including in respect of its decision to exclude UNFT and EIL from the TVM.

Consideration of these factors cannot reasonably lead to a decision which excludes UNFT and EIL true up from the TVM.

The AER's decision will increase the administrative burden on the AER and Evoenergy, including by requiring us to make a pass through application for any material change in our UNFT and EIL payments. This is an unnecessary administrative step, which would not occur if these costs were subject to a true up under the TVM. We cannot identify any administrative benefit from the AER's draft decision, and it is not evident to us that the AER has had regard to the consideration in NGR 97(3)(b).

[81] Houston Kemp (2026). Appendix 3.3 Assessment of the AER's draft decision on depreciation, January, p. 2.

[82] AER (2025). Draft decision Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components, November, p. 21.

NGR 97(3)(c) requires the AER to have regard to regulatory arrangements (if any) applicable to the relevant reference services before commencement of the proposed TVM. This factor supports our revised proposal, to continue treating UNFT and EIL in the manner they are treated in our current access arrangement for 2021–26.

The UNFT and EIL are also imposed on Evoenergy in its capacity as an electricity distribution network service provider. In the electricity context, these costs are treated as jurisdictional scheme amounts. The jurisdictional scheme regime allows DNSPs to recover their actual costs incurred in making payments under AER-approved jurisdictional schemes. These amounts are not included in a DNSP's revenue requirement, rather, they are accounted for in annual pricing proposals, with a true up mechanism for any under or over recovery. The jurisdictional scheme regime achieves a substantially similar outcome to a true up for the UNFT and EIL under the TVM.

Similarly, an annual true-up for UNFT is also provided for by the ACT's Independent Competition and Regulatory Commission (ICRC) in its economic regulation of water and sewerage services provided by Icon Water.[83]

Rule 97(3)(d) requires the AER to have regard to the desirability of consistency between regulatory arrangements for similar services. This factor supports the inclusion of a UNFT and EIL true up in the TVM, to ensure consistency with the treatment of these fees in respect of the supply of electricity services as well as, for UNFT, water and sewerage services.

Inclusion of UNFT and EIL true up in the TVM is not inconsistent with the incentive-based regime

In its draft decision, the AER notes that providing a true-up for UNFT and EIL payments in the TVM effectively funds these costs on a cost-of-service basis, which is inconsistent with the incentive-based framework. This is incorrect, and inconsistent with other components of the AER's draft decision.

It is common, under an incentive-based framework, to provide for the recovery of specific expenditure components in a manner which allows for recovery of actual costs, where doing so does not frustrate the intent of the incentive-based regime.

The NER jurisdictional scheme regime provides an example. The AEMC's determination on the *National Electricity (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010* explains why this approach is desirable and not inconsistent with an incentive-based regime. In particular, the AEMC concludes that:

- amounts of monies that DNSPs are required to pay as specified by legislation are not opex within the control of the DNSPs. While it would be prudent to assess opex within the DNSP's control for efficiency, there are no benefits to including such payments in the building block process,[84]
- administrative efficiency is enhanced by the provision of a specific mechanism for recovery of payments made by DNSPs under jurisdictional schemes, by removing the

[83] ICRC (2023). Price Direction, Regulated water and sewerage services, 1 July 2023 to 30 June 2028, pp 10-11.

[84] AEMC (2010). Final Determination, National Electricity (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010, p. 15.

requirement for the recovery of these payments to be addressed under the distribution determination and pass through processes,[85]

- the pass through mechanism requires the AER to make a determination on any pass through application taking into account various factors including the efficiency of a DNSP's decisions and actions in relation to the pass through event. This ensures that the pass through mechanism is used only for unexpected costs that would not otherwise be compensated in the DNSP's distribution determination. Changes in payments made under jurisdictional schemes should occur in the pricing proposal process, rather than through the pass through regime,[86] and
- the use of the pricing process to recover jurisdictional scheme amounts reduces the forecasting risk that exists when these amounts are included in the opex building block.

Each of these reasons is equally applicable to payments made in accordance with legislation by gas network service providers. The NGL and NGR do not need to contain a jurisdictional scheme regime, as the TVM already exists as a tool to recover such amounts in the appropriate manner.

We also observe that, if the AER considers it is inappropriate to exclude UNFT and EIL payments from base opex, on the basis that such treatment is inconsistent with an incentive-based regime, it should extend this logic to all costs. However, the AER's draft decision retains debt-raising costs and unaccounted for gas costs as category specific forecasts.[87] The AER's draft decision is internally inconsistent and provides no valid basis for the inclusion of UNFT and EIL in opex, without a true up under the TVM.

The pass through mechanism in our access arrangement is not an appropriate mechanism to deal with changes in costs

The AER's suggestion that material changes in these costs be recovered via the pass through mechanism in our access arrangement is inconsistent with the scheme and intent of that mechanism for the reasons set out in the AEMC's determination and summarised above.

The pass through mechanism in our access arrangement is analogous to the pass through regime established for electricity by the NER, which is intended to deal with costs that DNSPs incur as a result of unexpected events.[88] Generally, a change in an existing category of cost is not an unexpected event, particularly where there is a history of such changes occurring, as is the case with the UNFT and EIL. A change to the UNFT and EIL payments that Evoenergy must make is not an unforeseen event; we expect that such changes will occur, and, in circumstances where we have no control over these costs, our access arrangement should provide for them to be passed through in full, and without any reliance on the pass through mechanism in the access arrangement.

Further, the AER appears to suggest that a materiality threshold of 1 per cent should apply to any tax change pass through event included in our access arrangement to provide for UNFT and

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[85] AEMC (2010). Final Determination, National Electricity (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010, p. 16

[86] AEMC (2010). Final Determination, National Electricity (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010, p. 16.

[87] For unaccounted for gas (UAG), the true up relates to the volume of gas and the price of gas that is outside of Evoenergy's control, but not the benchmark target rate of unaccounted for gas (that is, gas lost) which is set in the access arrangement.

[88] AEMC (2012). Final Determination, National Electricity (Cost pass through arrangements for Network Service Providers) Rule 2012.

EIL payments.[89] This means that Evoenergy will bear the cost of any increase in UNFT and EIL that is less than the 1 per cent materiality threshold. The AER notes that, in respect of unforeseen costs that are relatively minor, a service provider should manage them by using up its existing expenditure allowance, or reprioritising or substituting its projects, to avoid seeking cost recovery through the pass through mechanism.

In circumstances where Evoenergy has no control over the changes in UNFT or EIL payments, it is not appropriate for Evoenergy to manage these costs at the expense of other projects or expenditure, as requiring Evoenergy to do this does not deliver any efficiency benefits, and hinders our ability to recover efficient costs. Despite the AER's assertion that Evoenergy should face incentives to seek a reduction in these costs, in practice, Evoenergy has no influence over the ACT Government or its costs for regulating the utilities sector.[90] Such an approach, as appears to be suggested by the AER, would undermine the independence of regulation. Jurisdictional charges are entirely outside of Evoenergy's control.

We note that it has been argued that utilities have some ability to minimise costs and cost volatility in respect of some charges, such as AEMO fees (by engaging with and assisting AEMO). However, our jurisdictional charges – in particular the entirety of the UNFT and the component of the Energy Industry Levy which relates to the costs of the ACT Government meeting its own national regulatory obligations – are of an entirely different nature. There is zero scope for us to minimise or reduce these costs. It is not Evoenergy's role, nor should it be, to influence the ACT Government budget, as suggested by the AER in its draft decision whereby cost recovery of jurisdictional charges should be designed as an 'incentive to lower costs'.[91] Jurisdictional budget decisions are the purview of democratically elected governments that need to consider the trade-offs required to balance the relevant government budget, such as the need to fund health care, education or other public infrastructure. Jurisdictional charges are defined as a regulatory obligation under the NGL, and a cost of service based approach ensures compliance with the NGO.

Lastly, we note that our jurisdictional charges are fundamentally different in terms of scale to charges faced by other gas distribution businesses. Jurisdictional charges make up a material proportion of:

- the revenue allowance (see Figure 6) – which is around 13 per cent of unsmoothed revenue (compared to the industry average of 1 per cent), and
- operating expenditure (see Figure 7) – constituting about 24 per cent of our opex, which is about double the next highest (AusNet) and more than 14 times higher than JGN.

This means that, even if the AER were to maintain its position that jurisdictional costs should be treated liked other components of opex for most businesses, a different approach should apply to our charges given their magnitude.

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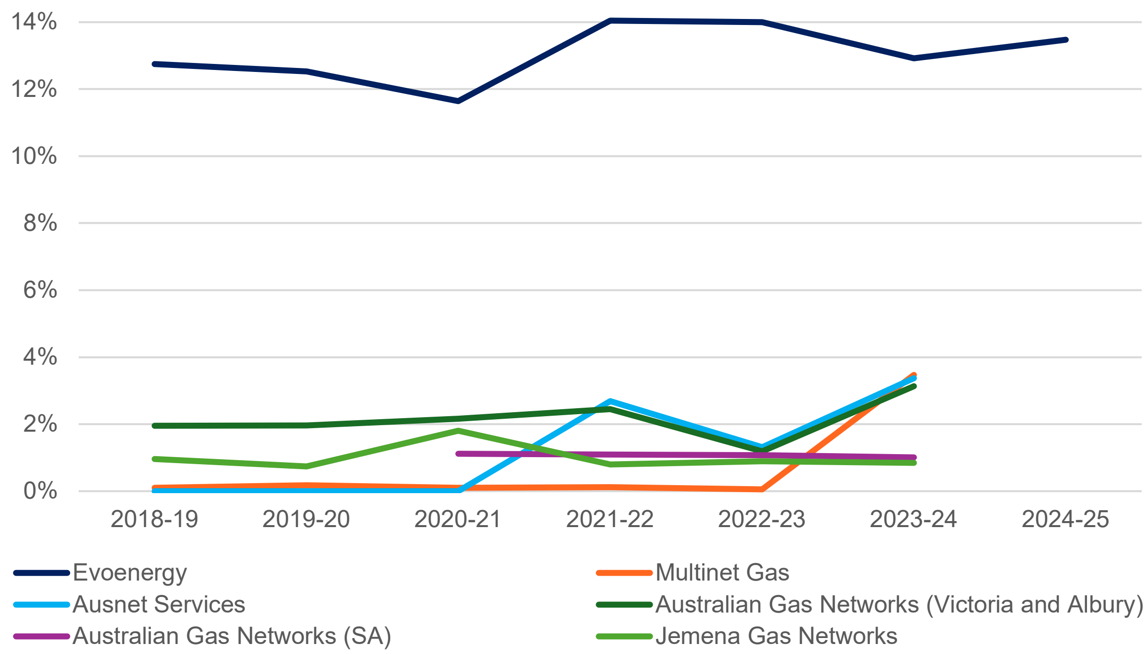
[89] The AER suggests that the tax change event could reflect the approach taken in its recent determination for JGN, which includes a materiality threshold of 1 per cent. This is consistent with the prescribed tax change event in the NER, which the AER also refers to.

[90] The purpose of the Energy Industry Levy is to recover the ACT Government's actual and forecast costs of regulating each energy industry sector. These costs include local regulatory functions performed by the Independent Competition and Regulatory Commission (ICRC), the Utilities Technical Regulator (UTR), and the ACT Civil and Administrative Tribunal (ACAT), as well as the Territory's contributions to national bodies such as the Australian Energy Market Commission (AEMC) under the Australian Energy Market Agreement (AEMA). See ICRC (2021). Guidance Note Energy Industry Levy, July.

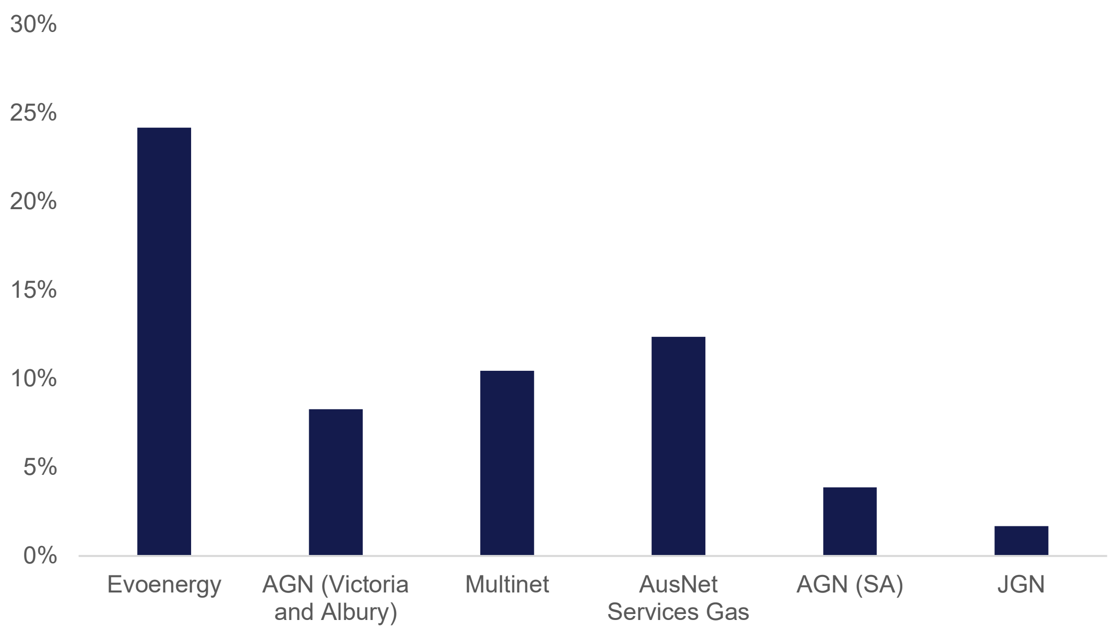
[91] AER (2025). Draft decision - Evoenergy access arrangement 2026–31 - Attachment 3 - Operating expenditure, November, p. 20

Figure 6 Jurisdictional charges as a proportion of unsmoothed revenue allowance ($nominal)



Source: Evoenergy analysis of RIN data (Table F4.1.2) and AER final decision PTRMs (updated for the cost of debt)

Figure 7 Jurisdictional charges as a proportion of opex



Source: Evoenergy analysis of 2023/14 RIN data (table F4.1.3)

See Attachment 5: Operating expenditure for further discussion on the UNFT and EIL category specific forecasts.

1.4 Consumer engagement on the TVM

1.4.1 Consumer engagement on the form of hybrid in response to the AER's draft decision

For this revised proposal, we consulted with our community forum and the ECRC on options for a hybrid TVM. This engagement was informed by the results of our prior NSW community forum, where we discussed the implications of demand uncertainty.

We presented three options:

1. Sharing hybrid (no revenue constraint, with 50/50 sharing where actual revenue is different to the AER's approved allowance for our efficient costs),
2. Narrow hybrid (2 per cent revenue constraint, with 50/50 sharing where actual revenues differ by more than 2 per cent from the AER's approved allowance for our efficient costs). We note that this 2 per cent figure reflects double the 1 per cent materiality threshold applied in the cost pass through regime, and
3. Broad hybrid (5 per cent revenue constraint, with 50/50 sharing where actual revenues differ by more than 5 per cent from the AER's approved allowance for our efficient costs), reflecting the AER's preference outlined in its draft decision.

Given the limited time available, we did not engage on alternative sharing ratios.

We presented an illustrative pricing scenario that forum members were already familiar with to compare the impact of each option in either a slower or faster energy transition (see Figure 8). For simplicity, these illustrative examples do not capture the timing or cash flow impacts of each mechanism.

Figure 8 Illustrative comparison of TVM options for revised proposal

If actual demand is different to the forecast

Forecast demand 10 customers paying $10.00 each = $100 network cost

		Slower transition	Faster transition	
Revenue cap (Evoenergy proposal)	Customers	**11**	**9**	Customers pay amount Evoenergy needs
	Cost to run network	$100.00		
	Cost per customer	$9.09	$11.11	
50/50 sharing hybrid	**Customer pays**	**$9.55**	**$10.56**	Customers pay more or less than Evoenergy needs
	Evoenergy revenue	$105.00	$95.00	
Narrow hybrid	**Customer pays**	**$9.64**	**$10.44**	Customers pay more or less than Evoenergy needs
	Evoenergy revenue	$106.00	$94.00	
Broad hybrid (AER draft decision)	**Customer pays**	**$9.77**	**$10.28**	Customers pay more or less than Evoenergy needs
	Evoenergy revenue	$107.50	$92.50	

42 *This is an illustrative worked example.* evoenergy

Official

Source: illustrative pricing scenario presented to Evoenergy's community forum.

When we asked customers to comment on which hybrid option they thought most appropriate in Evoenergy's circumstances (where a revenue cap was not included due to the AER's requirements in its draft decision), the majority preferred the 50/50 sharing option (with no revenue constraint). The primary reason for customers preferring the 50/50 sharing option was that it was considered the fairest with equal sharing of risk.[92]

1.4.2 Concerns with our earlier engagement on the TVM

While the AER acknowledged the stakeholder support received for our revenue cap proposal, it questioned the way we engaged on and presented the suitability of a revenue cap. The AER's concerns appear to relate to two issues raised in the CCP33's submission. The CCP33 concluded that 'customers continued to struggle with their understanding of the implications of the different TVM options as well as the objectivity of the information presented'.[93]

We consider that the conclusion of the CCP33 is invalid. Specifically, due to its late appointment by the AER in November 2024, the CCP33 did not observe any of our engagement before lodging the RSP. Those sessions were used for capacity building to explore different approaches to varying tariffs. We had not yet formed a view on the most appropriate TVM, and no view on which TVM would be most appropriate was presented to the community forum. The CCP33 had limited visibility into the engagement on our TVM, only observing later sessions after their appointment and after we lodged our revenue cap proposal.

The first concern of the CCP33 relates to the objectiveness of the information presented, with CCP33 considering we 'nudged' the community forum. The CCP33 pointed to the assessment criteria and ratings applied during our March 2025 engagement, and in particular the slide reproduced in Figure 9. The CCP33 highlighted our assessment of price variability, noting that 'customer price variability is a characteristic of a revenue cap.'[94]

However, it is not accurate to simply claim that price caps lead to stable prices and revenue caps lead to price volatility, because:

- price variability will occur regardless of the applied TVM due to updates for economic factors such as inflation and cost of debt,
- while price caps could lead to lower price stability within a period, as recognised by the AER, price caps can lead to higher volatility between periods.[95] We note that year-on-year price variability under a revenue cap can be very low, given that demand forecasts are updated every year, which smooths demand-driven variability through a rolling unders and overs mechanism, and
- price variability depends on *how* actual demand deviates from forecast demand set by the AER in its final decision. Price variability depends on whether demand fluctuations are symmetric or whether there is a growing divergence between the forecast and actual demand (as we demonstrate in section 1.3). Notably, it is the latter scenario which is the focus of our engagement.

These nuances were captured on the slide we presented to our community forum (Figure 9). We further note that the remainder of the assessment we presented is in line with the AER's

[92] Communication Link (2026). Appendix 1.1: Communication Link-Evoenergy community and customer forums, January, p. 28.

[93] AER (2025). CCP33 Advice to AER Evoenergy – Access Arrangement Proposal 2026-31, August, p.31.

[94] AER (2025). CCP33 Advice to AER Evoenergy – Access Arrangement Proposal 2026-31, August, p.30.

[95] AER (2021). Regulating gas pipelines under uncertainty, Information paper, November, p.54.

characterisation of the difference between a revenue cap and price cap. This slide was supported by the presentation of price outcomes under different demand scenarios, to show how demand forecasting risk is allocated.

Figure 9 Initial proposal assessment of TVM options

Adjusting prices: draft plan

	Revenue cap	Weighted average price cap	Hybrid
Guaranteed that **customers pay only what is needed** to maintain a safe and reliable gas network	✓	✗	✗
Consistency between gas and electricity network pricing approaches	✓	✗	✗
Low **administration costs** (e.g., risk of reopeners/regulatory period length)	✓	✗	✗
Low price variability if declining demand is faster/slower than forecast	✓ Medium to long term	✓ Short term	✓ Short term
Consistent with **emissions reduction** objectives	✓	✗	✗

The second main concern of the AER's appointed CCP33 is that customers struggle to understand the implications of different TVM options.[96] CCP33 noted that there was some support for a revenue cap but that not all workshop participants voted in the poll, suggesting that some of them were unsure about the topic or the "right" answer.[97]

We consider that uncertainty about the topic and the "right answer" implies the reverse: that customers broadly understood the complexities of the issue.

We note that the AER considered the issue in three different processes over three years, before coming to a view on what should apply for a network in JGN's circumstances.

Although complex information and concepts were discussed, as noted by the ERAP in relation to the community forum's development: 'participants showed an impressive ability to process very complex topics and content.'[98]

While we accept that not all customers and stakeholders will understand all nuances of a TVM and that there is always room for improvement when it comes to customer engagement, we are concerned that customers' views are being discounted and not heard.

This frustration was also communicated by our community forum members in our revised proposal engagement. A sample of comments from members, reproduced verbatim, include:

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[96] AER (2025). Draft decision Evoenergy (ACT) access arrangement 2026 to 2031, Attachment 5 , November, p. 22

[97] AER (2025). CCP33 Advice to AER Evoenergy – Access Arrangement Proposal 2026-31, August, p.31.

[98] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31-Appendix 1.5, June, p. 25.

- *'The AER also appeared to assume community members were not smart enough... It felt quite insulting given the extensive consultation had'*[99]
- *'It's time to do something new. Let's be the first jurisdiction to do something different in terms of pricing (revenue cap) and accelerated depreciation. Not liking a revenue cap, just because you don't think we were well informed is not a valid reason, it needs to be backed with actual evidence as to why it is not beneficial'*[100]
- *'Is the regulator treating ACT like the other states and not looking at ACT specific policy?'*[101]
- *'It just seems like they're totally ignoring the ACT, as a unique case, and just looking at what they're doing in every other state.'*[102]
- *'It does not seem to have considered what the ACT position is towards going zero use of Gas.'*[103]
- *'Customers should be heard and AER needs to apply a forward thinking approach. This is the approach taken in these customer feedback sessions. I am alarmed, deeply disappointed by the AER draft response'*[104]

Even if the AER has some concerns around elements of our engagement approach, the AER should have greater regard to the extensive nature of our engagement on this issue (discussed at multiple community forums) and the direct feedback provided by customers.

Overall, Evoenergy agrees with customer sentiment that the AER's engagement with our proposal was limited. When the community forum was presented with the reasons for the AER's preferred hybrid, a customer noted:[105]

> *'Evoenergy should have provided more context on why the AER chose this [hybrid] method to help to understand the drivers for both Evoenergy and the AER.'*

Evoenergy could not provide the community forum with more context because there was a lack of reasoning in the AER's draft decision, other than to point to its regulatory precedent for JGN operating in NSW. We note that the AER, in its draft decision, did not provide justification for why its preferred hybrid approach is not consistent with its other regulatory determinations, such as for electricity networks. We agree with our customers feedback that the AER's engagement with our proposal was limited, and is lacking evidence to support its alternative view to apply a hybrid TVM.

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[99] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums, January, p. 35.

[100] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums, January, p. 30.

[101] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums-January, p. 26.

[102] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums-January, p. 26.

[103] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums-January, p. 26.

[104] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums-January, p. 30.

[105] Communication Link (2025). Appendix 1.1: Communication Link-Evoenergy community and customer forums, January, p. 28.

1.5 Our revised TVM proposal

1.5.1 Our revised proposal for a 'narrow' hybrid TVM

While we maintain that a revenue cap is the only appropriate TVM in our circumstances, the AER draft decision requires Evoenergy to propose a hybrid. Given this, we have developed a hybrid mechanism that is more appropriate in the context of our network and somewhat mitigates the extent of non-compliance with the NGL and NGR associated with the JGN style hybrid TVM contemplated by the AER's draft decision.

Under our narrow hybrid TVM, a partial revenue true-up applies if actual revenue for a year is 2 per cent lower or higher than the AER's approved allowances for our efficient costs. Under the narrower hybrid TVM, we will bear 100 per cent of the risk of the demand forecast in the final decision being incorrect up to a 2 per cent deviation of actual demand, and 50 per cent of the risk of demand deviations beyond the threshold with customers holding the remaining 50 per cent. We have also included a larger side constraint for our demand market tariff class, implemented through an S-factor, to facilitate rebalancing revenue from the volume to demand market if required.

In developing our narrow hybrid TVM, we also considered a hybrid option without a revenue constraint and where all deviations in actual revenues from the AER's allowed revenues would be shared on a 50/50 basis between Evoenergy and customers. However, we anticipated that it would not suffice to resolve the AER's concerns, given its preference for a WAPC-hybrid TVM.

Although we consider that the AER's concerns are unwarranted and without evidence, and its decision to require the application of a hybrid TVM is contrary to the NGL and NGR, in anticipation that the AER will not change its views, we have proposed a narrow hybrid TVM. However, if we have misunderstood the AER's preference for a WAPC-hybrid with a revenue constraint, we would welcome further engagement with the AER on a 50/50 sharing arrangement without a revenue constraint. This was the preferred hybrid option identified by our community forum and better accounts for asymmetric demand forecasting risk.

For the avoidance of doubt, and in light of legal considerations and the views of our community in response to the AER's draft decision, we would welcome a final decision that applies a revenue cap as our first preference.

We maintain that under a narrow hybrid TVM approach – particularly when applied in combination with the AER's 4 per cent real annual network price increase limit, a higher demand forecast based on historical trends, and a flatter tariff structure – Evoenergy will be denied an opportunity to recover our efficient forecast costs, and will not be compensated for our regulatory and commercial risks. However, while the issues with a hybrid TVM outlined in section 1.3 above are still present under our narrower hybrid, as explained further below, they exist to a lesser extent compared to a JGN style hybrid (in the context of our network).

Our narrow hybrid TVM has been developed based on:

- **Customer views** – when presented with a range of hybrid options, customers mostly supported a design with no revenue constraint and 50/50 sharing of all revenue deviations. However, while we agree with our community's views, we consider this is unlikely to be acceptable to the AER given its strong preference for a JGN style hybrid, and we consider that customers would likely prefer the narrow hybrid to the broad hybrid. We provide further information in section 1.4.

- **There is no material difference across hybrid TVMs with respect to tariff variability** – our modelling demonstrates that there is no material difference in tariff volatility between a narrow hybrid TVM and a broad hybrid (i.e. a JGN style hybrid TVM). This was tested in both a symmetric demand forecasting risk scenario, as well as a scenario in which demand is lower than forecast on a sustained basis. We present our analysis in section 1.3.
- **The evolving unique context we face** – which is materially different to other Australian jurisdictions, including NSW and SA. We are uniquely exposed to high levels of asymmetric demand risk and cannot reasonably control or influence demand. Further, our demand characteristics materially differ to other jurisdictions due to our highly residential customer base with a highly seasonal demand profile, and the fact that residential customers are on more motivated and better enabled to electrify early. We provide further information in section 1.3.

NGL and NGR non-compliance somewhat reduced (but not eliminated) by a narrow hybrid TVM

In section 1.3, we note that the AER's draft decision is not consistent with the NGL and NGR, as it:

- does not provide us with an opportunity to recover at least our efficient costs, and
- does not provide us with effective incentives to promote economic efficiency in respect of investment in, and operation of, our network.

For these reasons, we maintain our view that our access arrangement should be subject to a revenue cap TVM. However, we consider that these issues would be mitigated, to an extent, but not eliminated, by the adoption of a narrow hybrid TVM because:

- A hybrid TVM makes our ability to recover at least the AER's approved allowances for our efficient costs dependent on the AER's demand forecasts being accurate, in the context of demand uncertainty and with asymmetric demand risks. The higher the revenue constraint threshold, the greater level of risk we bear, and the greater the expected extent of under recovery of the AER's approved allowances for our efficient costs. The 2 per cent revenue constraint lowers this risk and, while we will still be expected to under recover the AER's approved allowances for our efficient costs, it increases the extent of our expected recovery of the AER's allowances for our efficient costs, relative to a 5 per cent threshold.
- As a 2 per cent revenue constraint reduces our reliance on the AER's demand forecasts being accurate, compared to a 5 per cent threshold, our incentives to grow (or minimise the decline in) demand are also reduced (but not eliminated as would be the case under a revenue cap). This is appropriate in circumstances where we cannot reasonably, and should not be provided with an incentive to, grow (or minimise declines in) demand, in the ACT legislative and policy environment.
- A hybrid TVM allows for a partial true-up of revenue under or over recovery (beyond the revenue constraint threshold) which, in our circumstances of demand uncertainty and asymmetric demand risk, is closer to an economically efficient outcome (for both allocative and productive efficiency) compared to a price cap (but still less efficient than a revenue cap), for gas services and with energy substitutes.

Our unique regulatory context

We note that the AER is not currently precluded from considering jurisdictional specific circumstances, to the extent that these are relevant to our ability to recover at least our efficient costs and be provided with effective incentives to promote economic efficiency. Indeed, if our unique regulatory context means that a hybrid (and more so under a broad TVM than a narrow TVM) would act to prevent us recovering the AER's allowances for our efficient costs, the AER must take this into account when determining whether our access arrangement will be consistent with NGO and the revenue and pricing principles.

1.5.2 Our revised proposal for a true up of jurisdictional charges under the TVM

Our revised proposal is that UNFT and EIL costs should be treated in the same way as the current access arrangement period, where they are included as category specific forecasts in our opex and subject to an annual true-up via the TVM. This is for the reasons advanced in section 1.3.3.

2. Transportation (including metering) tariff structure

2.1 Overview of our initial Transportation (including metering) tariff structure proposal

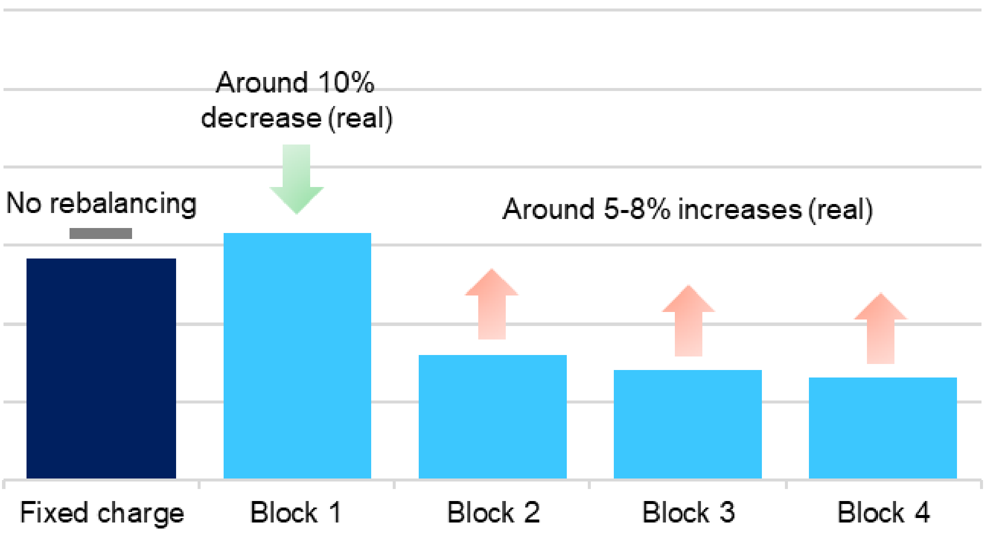
Our initial proposal for our Transportation (including metering) reference service tariffs for the 2026–31 access arrangement was to retain the tariff classes and tariffs established in our 2021–26 access arrangement, being:

- the demand class (for very large customers, expected to use more than 10 TJ per annum), comprising the Demand Capacity (DC) and Demand Throughput (DT) tariffs.
- the volume class, covering all other residential and commercial customers on the gas network, and comprising the Volume Individual (VI) and Volume Boundary (VB) tariffs.

We also proposed to retain the existing block structures within the tariffs to preserve administrative simplicity and minimise transaction costs for retailers and customers. We maintained that keeping the block structure would also support our ability to adjust prices in response to usage changes within particular blocks (which broadly represent different cohorts of customers on our network).

While we did not propose structural changes to our tariffs, our initial proposal involved a gradual and measured transition towards a flatter VI tariff (which applies to over 99 per cent of customers on our network). Our proposed flattening was to target a real reduction of approximately 10 per cent in the Block 1 charge, with a corresponding increase of 5–8 per cent in Blocks 2–4 to maintain the same level of revenue (see Figure 10).

Figure 10 Illustration of proposed flattening of VI tariff block charges



Note: Evoenergy proposed that the final price levels would be determined through annual tariff variations, approved by the AER each year in the 2026–31 access arrangement period.

Our rationale was that a gradual flattening of the VI tariff would:

- improve affordability for smaller customers (who predominantly consume within Block 1); and
- increase the marginal price of consumption for larger users (in Blocks 2–4), consistent with the ACT Government's policy to phase out gas and the emissions reduction component of the NGO.

We considered an incremental approach was necessary to manage bill impacts and mitigate the risks of more variable demand typically seen in Blocks 2–4.

We did not propose any flattening for the VB tariff and demand tariffs, given the specific characteristics of these customers, including their largely flat loads, unique electrification challenges, and the low likelihood of a demand response.

Similar to the approach taken in the 2021–26 access arrangement period, we proposed to automatically reset chargeable demand for DC tariff customers from 1 July 2026 if this would result in a reduction in a customer's network charges.

2.2 The AER's draft decision on our Transportation (including metering) tariff structure proposal

The AER's draft decision accepted our proposal to retain the existing tariff classes and tariffs for transportation (including metering) reference services.

However, the AER's draft decision did not accept our proposal for a gradual flattening of the VI tariff. Instead, the AER's draft decision requires Evoenergy to:[106]

- Completely flatten the outer blocks of the VI tariff in year 1 of the access arrangement. This involves consolidating Blocks 2, 3, and 4 into a single usage block, effectively establishing a two-block tariff structure.
- Similarly flatten the VB tariff to a two-block structure in year 1.
- Consider flattening the demand tariffs or set out a clear transition plan to do so over the 2026–31 access arrangement period.

The AER reasoned that Evoenergy's declining block tariffs promote the use of gas and are in conflict with the emissions reduction component of the NGO.[107] The AER considered that, since the price differences between the existing outer blocks are already relatively small, consolidating them would simplify the tariff structure and remove the implicit reward for higher consumption without causing significant bill impacts. The AER observed that retaining a higher Block 1 charge is reasonable given that it is paid by all customers who use gas, and reflects the fixed nature of network costs.[108]

The AER's draft decision acknowledges concerns from ActewAGL Retail that flattening of the tariff blocks could negatively impact vulnerable customers who are least able to electrify (a concern shared by Evoenergy in its initial proposal). However, the AER concludes that flattening

[106] AER (2025). Draft decision – Evoenergy (ACT) access arrangement 2026–31 – Attachment 5, November, p. 14.

[107] AER (2025). Draft decision – Evoenergy (ACT) access arrangement 2026–31 – Attachment 5, November, p. 14.

[108] AER (2025). Draft decision – Evoenergy (ACT) access arrangement 2026–31 – Attachment 5, November, p. 14.

would result in minimal bill impacts, and that ACT Government programs could help to mitigate any negative impacts.

The AER's draft decision on our proposed tariff structures for the 2026–31 access arrangement period is summarised in Table 4.

Table 4 AER's draft decision on Evoenergy's tariff structure proposal

Tariff	Evoenergy's initial proposal	AER's draft decision
Volume Individual (VI)	Retain the existing Block structure, and gradually flatten the price levels to achieve an approximate 10 per cent reduction in Block 1, with commensurate increases in Blocks 2-4 of approximately 5 to 8 per cent over the period.	Establish a two-block structure from year 1 (by consolidating Blocks 2–4).
Volume Boundary (VB)	No change	Establish a two-block structure from year 1 (by consolidating Blocks 2–3).
Demand Capacity (DC)	No change	Comparably flatten the demand tariffs, or lay out a plan to transition to flatter tariffs.
Demand Throughput (DT)	No change	

2.3 Our response to the AER's draft decision and revised tariff structure proposal

Evoenergy maintains that the 2026–31 tariff structures in its initial proposal reflect our community's views that tariffs should achieve emissions reductions objectives while providing relatively lower bill increases for smaller customers. Nevertheless, Evoenergy has incorporated the requirements of the AER's draft decision into our revised proposal. Accordingly, our revised proposal adopts the following changes:

- **Volume Individual (VI) Tariff:** we will implement a two-block structure starting from year 1 (2026–27). This consolidates the previous Blocks 2, 3 and 4 into a single block applying to gas consumption above 3.75 GJ per quarter. Block 1 will be retained with the previous threshold covering the first 3.75 GJ of gas consumption per quarter.
- **Volume Boundary (VB) Tariff:** we will also move the VB tariff to a two-block structure in year 1 (2026–27). This removes the previous Block 3 charge, with the Block 2 charge now applying to all gas consumption above 112.50 GJ per quarter.
- **Demand Capacity (DC) Tariff:** we propose to transition to a flatter DC tariff by incrementally equalising Block 2 and Block 3 prices over the course of the 2026–31 access arrangement period, and effectively achieving a two-block structure by 2030–31.

This measured approach acknowledges the unique circumstances and complexity facing this group of customers, as explained in our initial proposal.[109]

- **Demand Throughput (DT) Tariff:** we are not proposing any changes to the structure of the DT tariff as it already has a flat structure with a single block for all gas usage and is consistent with the requirements of the draft decision.

While we have adopted the structural changes required by the AER's draft decision, we retain concerns regarding the impact of these changes on our ability to manage demand variability. The AER's draft decision does not provide compensation for the additional commercial risks that result from its preferred flatter tariff structure as is required under the NGL.

As explained in our initial proposal, usage in the outer tariff blocks (e.g. Blocks 2–4 for the VI tariff) is historically the most variable component of our demand, driven significantly by weather and partial electrification of gas appliances.[110] Further, as explained in our initial proposal, the VI tariff covers 99.9 per cent of customers on our network, and the consumption blocks are designed to reflect different cohorts of residential and commercial customers across a wide range of consumption levels. Consolidating the outer tariff blocks into a single rate reduces the levers available to Evoenergy to respond to demand variability and stabilise revenue recovery across the various markets segments served by the VI tariff.

Unlike some other gas distributors (e.g. JGN), Evoenergy does not have separate volume tariffs for residential and commercial customers of different sizes. Based on the AER's draft decision, Evoenergy will have two consumption blocks on its VI tariff within which to manage revenue recovery across 99.9 per cent of its customer base, compared to JGN's eight blocks across its small and large VI tariffs. With a flatter structure, Evoenergy will have fewer tariff blocks overall and less ability to stabilise revenue and manage bill impacts by rebalancing revenue recovery across tariffs and tariff components.

As discussed in section 1.1.1, we initially proposed a revenue cap TVM to ensure that customers and Evoenergy did not bear demand forecasting risk. However, as the AER's draft decision rejected Evoenergy's proposed revenue cap TVM and instead requires a hybrid TVM, Evoenergy and its customers face the risk of the demand forecast being wrong.

To help mitigate this risk, and promote price stability for all customers, our revised proposal includes a small additional 2 percentage point increase to the fixed charges and Block 1 charges in our tariffs.[111] This adjustment:

- increases the proportion of revenue recovered from the most stable tariff components (fixed and Block 1 charges), and
- reduces reliance on the outer consumption block(s) for revenue recovery, thereby somewhat reducing the potential for revenue under- or over-recovery if actual demand differs from forecasts.

[109] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31 – Attachment 7, June, pp. 20–21.

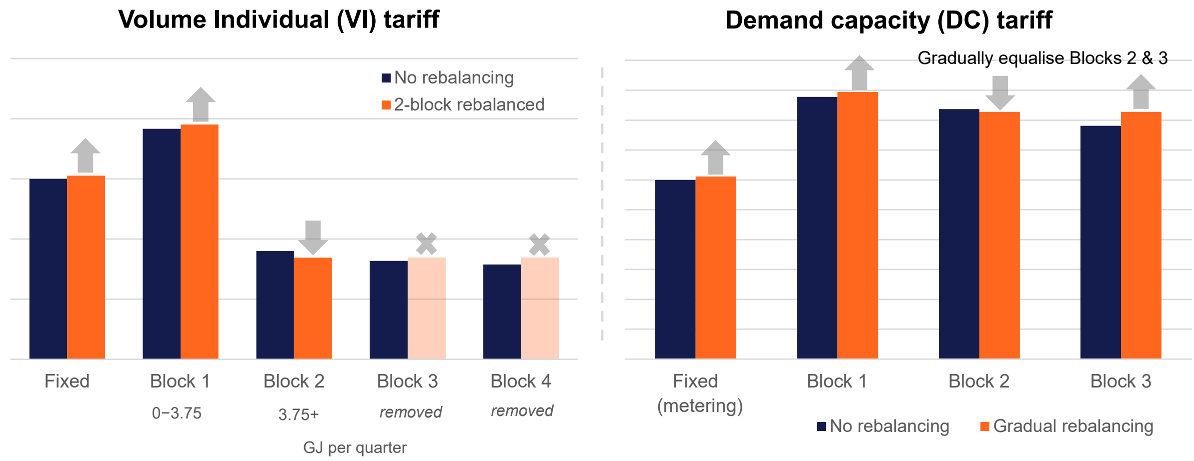
[110] Evoenergy (2025). ACT and Queanbeyan-Palerang gas network access arrangement 2026–31 – Attachment 7, June, pp. 18–19.

[111] This is implemented as an increase to the fixed charges (including metering charges) and Block 1 charges that is 2 percentage points higher than the average CPI-X increase in year 1 of the access arrangement period.

This adjustment is in line with the AER draft decision finding that a higher Block 1 charge is reasonable given that it is paid by all customers who use gas, and reflects the fixed nature of network costs.[112]

Figure 11 illustrates our revised proposal for the VI tariff and DC tariff, being our two largest tariffs. For the VI tariff, removing Blocks 3 and 4 requires decreasing the new Block 2 charge to maintain the same revenue (because Blocks 3 and 4 were previously priced lower). For the DC tariff, gradual flattening involves decreasing the Block 2 charge and increasing the Block 3 charge to equalise the two outer blocks by 2030–31.

Figure 11 Revised proposal flattening of VI tariff and DC tariff



2.3.1 Implications on managing forecasting risk

Evoenergy initially proposed a revenue cap TVM for the 2026–31 access arrangement period. We consider this is the only appropriate mechanism to manage the significant demand forecasting uncertainty associated with the ACT's energy transition, as it effectively decouples revenue recovery from the variation between forecast and outturn gas volumes. However, the AER's draft decision requires Evoenergy to implement a hybrid TVM, which means Evoenergy and its customers will bear the risk of the AER's demand forecast being wrong.

This risk is compounded by the AER's concurrent requirement to consolidate tariff blocks, which concentrates volume risk in a small number of charging parameters. As we move towards a flatter tariff structure, we will have fewer blocks to adjust during annual tariff variations to mitigate revenue recovery risk and manage customer bill impacts. As discussed in the preceding section, we also have fewer tariffs overall compared to other gas distributors which further limits our ability to manage forecasting risk. In this context, and alongside our unique demand characteristics and strong policy context, it is critically important that the hybrid TVM design include a narrow threshold, as described in section 1.5. It is equally important that the AER's demand forecast accurately reflects the future intentions of our customers and policy impacts, rather than relying on historical trends (see Attachment 2: Demand).

2.3.2 Our engagement following submission of our initial proposal

In both discussions with our deliberative forums and with retailers, concerns were raised about the reduction of tariff blocks and the impact for smaller VI customers, compared to our

[112] AER (2025). Draft decision – Evoenergy (ACT) access arrangement 2026–31 – Attachment 5, November, p. 14.

proposal.[113] Retailers also observed that these changes raise a number of implementation issues (including administration and billing system costs) and could increase costs for hardship and small customers, relative to our initial proposal.

[113] Appendix 1.1: Communication Link-Report of feedback from community and customer forum sessions-January 2026, p. 25; Attachment 1: Revised plan engagement report-January 2026, p. 17.

Glossary

Term or acronym	Definition
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CAB	Capital asset base
Capex	Capital expenditure
CCP33	AER Consumer Challenge Panel 33
CPI	Consumer price index
Decommissioning	Decommissioning refers to the complete or partial shutting down and removal of the infrastructure of the gas network that is no longer in use.
ECRC	Energy Consumer Reference Council
EIL	Energy Industry Levy
ERAP	Energy Regulatory Advisory Panel
GN26	Evoenergy's gas network plan for the 2026–31 access arrangement period
GJ	Gigajoule – unit of measurement of energy consumption
IEP	ACT Government's Integrated Energy Plan
JGN	Jemena Gas Networks
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSP	Network service provider
NSW	New South Wales
Opex	Operating expenditure
RSP	Reference Service Proposal
TJ	Terajoule – unit of measurement of energy consumption
The Rules or Rules	National Gas Rules
TVM	Tariff Variation Mechanism
UAG	Unaccounted for gas
UNFT	Utilities (Network Facilities) Tax
VB	Volume Boundary tariff
VI	Volume Individual tariff
WAPC	Weighted average price cap
WPI	Wage Price Index