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Thursday, 24 September 2026

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Dear Anna,

Re: Electricity Network Regulation Review – Package 2 consultation

The Australian Energy Regulator (AER) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC's) Electricity Network Regulation Review – Package 2 consultation paper. We agree that it is important for the sector to consider now whether the regulatory framework for electricity networks remains fit for purpose as the NEM continues to change.

Package 1 is exploring important issues at the boundary of the regulatory framework. In our submission to Package 1, we recommended that the review consider fundamental questions about how we regulate across those boundaries. The topics considered in Package 2 (including the revenue determination process, incentives and risk allocation and compensation) are equally important and fundamental to our framework.

The existing framework remains a strong foundation

The existing economic regulatory framework has served consumers well and remains a strong foundation for network regulation. Ex ante incentive regulation remains an effective means of addressing information asymmetry between the regulator and regulated networks, and many of the mechanisms considered in Package 2 remain appropriate to the problems they were designed to address.

However, as our Future of electricity network regulation information paper highlighted, the framework must increasingly respond to different regulatory problems.¹ In asking whether what and how we regulate continues to align with why we regulate as the electricity system changes, our information paper identified a growing coordination issue: efficient outcomes increasingly depend on interdependent decisions made through shared network infrastructure, but the regulatory framework remains principally designed to manage monopoly pricing and investment.

¹ AER, [Future of electricity network regulation: Information paper](#), June 2026.

The framework must adapt to changing network functions

Economic network regulation developed for a system in which networks primarily contributed to efficient outcomes by providing sufficient capacity at efficient cost and maintaining required levels of reliability, security and service. As a result, the regulatory framework was designed primarily around the efficient provision of network capacity and defined network services by individual regulated businesses.

Package 2 provides an opportunity to consider how economic regulation should promote efficient operation and use where benefits to consumers are realised across different parts of the electricity system and are not captured through an individual network's investment or expenditure decision. This may help distinguish where existing expenditure and incentive mechanisms remain appropriate, where risk allocation may need to change, and where an emerging network function may require a different regulatory response or tool.

The AER is adapting existing regulatory tools

Where we have sufficient discretion, we are considering how we can use the tools we have to adapt to emerging challenges and opportunities. We are doing so in line with our 2026–30 strategic plan objectives to drive more efficient utilisation of electricity distribution networks, support efficient and timely investment in transmission, efficiently deliver regulatory outcomes and minimise regulatory burden.² For example, we are:

- assessing existing and potential measures of efficient electricity network utilisation
- reviewing guidelines for distribution planning, data centre connections, shared assets and ring-fencing (relevant to Package 1 of the AEMC review)
- finalising a guideline on network resilience
- considering the control mechanism (form of regulation) for electricity distribution standard control services (SCS) and alternative control services (ACS)
- hosting stakeholder roundtables and developing guidance for electricity network tariff reform.

We will progress these work programs in parallel with the AEMC review, and in timeframes that support engagement with electricity distribution network businesses and their stakeholders ahead of the next round of revenue determinations. Therefore, in line with the review's prioritisation criteria, the AEMC may wish to place greater emphasis on issues that are not already being progressed through established reviews or other regulatory work programs, as well as where the review is best placed to consider framework reforms to promote efficiency through the energy transition. While work under way at the AER may help clarify and improve the operation of the existing framework (and, in doing so, may inform the AEMC review), the AEMC review is a valuable opportunity to consider more broadly where the framework itself may no longer remain fit for purpose.

In some cases, there is an opportunity to reduce prescription which may have outlived its usefulness as the framework and sector have matured. Reducing prescription can ease administrative and regulatory burden while enhancing the framework's ability to adapt

² AER, [Strategic plan 2026–2030](#), August 2026.

through the energy transition. For example, a more principles-based and agile revenue determination process (including a more flexible Framework and approach or substitute process) can achieve efficiencies and focus effort where it will have most impact on consumer outcomes.

Package 2 should focus on foundational framework questions

However, simply improving flexibility and changing how we use existing tools is not enough. We must consider whether some of the foundations of the framework remain fit for purpose. While these foundational arrangements have been effective in promoting efficient outcomes to date, this does not necessarily mean they will be the appropriate arrangements to meet the challenges the future holds.

Package 2 provides an opportunity to consider these questions systematically. For example:

- How should risk be allocated between networks and consumers to respond to the needs of the energy transition without weakening efficiency incentives?
- How should the framework govern access to, allocation and efficient use of network capacity?
- What should be achieved through obligations rather than financial incentives?

We recommend the AEMC examine these foundational issues because they have implications across the framework and because changes made in isolation can have unintended consequences.

Regulatory tools should match the problem being addressed

A useful starting point is to identify the function or decision that needs to be governed (now and in the future), the regulatory problem associated with it, and then the tools best suited to address that problem. This is particularly important because some emerging functions do not present the same regulatory problem that the existing framework and its tools were principally designed to address.

For example, electrification, two-way flows and more active use of consumer energy resources (CER) and other distributed resources are making the amount, location and timing of available network capacity increasingly important. Distribution networks will increasingly make decisions about:

- who can connect and on what terms are they able to consume electricity from the grid or provide generation back into the grid
- how available capacity is allocated when the network is constrained
- how firm and flexible capacity is reflected in connections, planning, pricing and operation.

These decisions raise questions about access, information and the exercise of discretion that are not resolved by determining the level of network expenditure alone. They are different functions presenting different regulatory problems – as such, they may require different regulatory tools.

In other cases, the problem may remain the same but the effectiveness of an existing regulatory tool may be impacted by changes in the context in which that tool is applied. For example, we are seeing significant uplifts in investment in transmission networks, much of it driven by high-value Integrated System Plan (ISP) projects presented to us as contingent project applications. The growing scale and use of this and other uncertainty mechanisms is changing how the incentive framework operates in practice. This makes it increasingly important to test whether those mechanisms continue to allocate risk appropriately and preserve meaningful incentives for efficient forecasting, procurement and delivery. While incentive-based regulation should remain the basis of the framework, the AEMC should examine whether the balance of risk between NSPs and consumers remains appropriate, particularly for high-value ISP projects.

Priority directions for Package 2

We welcome the AEMC considering in Package 2 not only how existing mechanisms can be improved, but whether they remain well suited to the regulatory problems they are intended to address.

Ex ante incentive regulation remains a strong foundation where the principal regulatory problem is information asymmetry about efficient costs and NSPs can meaningfully manage expenditure risk. However, Package 2 should examine whether it remains the best approach across all network activities and projects as the transition changes the nature of expenditure, uncertainty and network functions.

In particular, the growing use of uncertainty mechanisms makes it important to ensure incentives are not progressively weakened by transferring to consumers risks that NSPs are better placed to manage. The transition is also increasing the importance of decisions that sit alongside expenditure regulation. In the distribution system, for example, the terms on which firm and flexible access are provided will affect planning assumptions, the capacity networks need to provide and the expenditure consumers fund. Access, planning, expenditure incentives, form of control and the efficient use of existing capacity therefore need to be considered together.

The same approach should guide the other issues raised in Package 2.

- Sources of any capex–opex bias should be addressed through targeted responses that take into account the costs and benefits of interventions.
- Innovation mechanisms should address a demonstrated barrier to efficient experimentation.
- Financial incentives should be used where NSP behaviour can materially affect an observable outcome, rather than where an obligation is sufficient to establish the required standard.
- Determination processes should be reviewed to reduce outdated prescription, improve flexibility and clarify roles and responsibilities while preserving transparency, consumer input and robust regulatory outcomes.

We encourage the AEMC to use Package 2 to consider these interactions across the framework, while avoiding unnecessary changes to mechanisms that continue to work well and remaining open to more foundational change where the regulatory problem has

changed. This would provide a clearer basis for determining what should be retained, what can be simplified or refined, and where the changing role of networks requires a different regulatory approach.

The Attachment provides detailed feedback on the priority issues and areas of the framework that may need to evolve. We also welcome engagement with the AEMC on other issues. For questions about this submission, please contact [REDACTED].

Yours sincerely,

[REDACTED]

Lynne Gallagher
Member, Australian Energy Regulator

Submitted online on: 24.09.2026

Encl.: Attachment – Detailed feedback (23 pages)

Attachment – Detailed feedback

This attachment sets out our detailed feedback on the AEMC's Electricity Network Regulation Review – Package 2 consultation paper.

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Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
Capex	Capital expenditure
CCP	Consumer Challenge Panel
CER	Consumer energy resources
CESS	Capital expenditure sharing scheme
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DSO	Distribution Service Operator
EBSS	Efficiency benefit sharing scheme
F&A	Framework and approach
ICT	Information and communications technology
ISP	Integrated System Plan
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network service providers
Opex	Operating expenditure
REZ	Renewable Energy Zone
RIT-D	Regulatory investment test for distribution
RIT-T	Regulatory investment test for transmission
STPIS	Service target performance incentive scheme

Regulatory approach through the energy transition

The energy transition is increasing uncertainty in the planning and operation of the system as a whole – the generation mix is changing, new technologies and business models continue to emerge and demand flexibility is increasingly required. This uncertainty is changing some network activities and creating new regulatory needs. Ex ante incentive regulation should remain the starting point where efficient expenditure can be reasonably assessed and NSPs retain meaningful control over costs and outcomes. Where those conditions do not hold – such as for some high-value ISP projects – or the issue concerns conduct, access or information rather than expenditure efficiency, a different mix of assessment, risk allocation, obligations and incentives may be warranted.

Applying ex ante incentive regulation through the energy transition

The existing regulatory framework remains well suited to the expenditure problem it was designed to address. Ex ante incentive-based regulation addresses the information asymmetry between NSPs and the regulator while giving NSPs incentives to manage expenditure efficiently over the regulatory period.

The regulator establishes an expenditure allowance and incentive framework within which the NSP retains meaningful control over its costs and outcomes. It does this by setting expenditure allowances for a five-year period at an aggregate rather than project-specific level. Incentive mechanisms encourage the NSP to pursue efficient expenditure (for example, through the Capital Expenditure Sharing Scheme and Efficiency Benefit Sharing Scheme), while service performance incentives protect against efficiencies being achieved at the expense of service outcomes (for example, through the Service Target Performance Incentive Scheme).

The framework also uses different assessment approaches according to the nature of expenditure. For recurrent expenditure, benchmarking of operational expenditure and revealed costs can provide information about efficient expenditure. For large or bespoke projects, more detailed assessment may be required. This allows the framework to retain the benefits of incentive regulation while applying greater scrutiny where aggregate or historical information is less informative.

Incentive-based regulation is most effective where the regulator can establish a reasonable expenditure baseline, the NSP has discretion over how it meets its obligations and the NSP has meaningful control over the costs and outcomes against which the incentive operates. Risks that cannot reasonably be reflected in the ex ante allowance or are outside the NSP's control are addressed through the framework's uncertainty mechanisms, including cost pass throughs, contingent projects and ex post reviews. These mechanisms complement the incentive framework by allocating particular risks differently where appropriate and their use does not, of itself, represent a departure from incentive-based regulation.

This approach to ex ante incentive-based regulation has worked well in practice and should continue to be the basis for how we regulate. However, uncertainty is growing. Since 2020, we have assessed 65 cost pass throughs and 14 contingent projects, including a growing number of high-value ISP projects for transmission NSPs. Increasing use of uncertainty mechanisms makes their design and interaction with the broader incentive-based regulatory framework increasingly important.

State-based schemes, such as the NSW Renewable Energy Zone (REZ) framework, are also resulting in large capex-intensive projects being assessed and delivered under alternative regulatory frameworks, while retaining cost recovery from monopoly providers' customers. As state schemes, these need not reflect the National Electricity Objective and instead reflect broader state-based policy objectives.

At the same time, the energy transition is changing the characteristics of activities and services undertaken by networks. In some cases, this may change the information available to the regulator, the degree of control an NSP has over costs or outcomes, or the way risks are most efficiently allocated. Emerging network functions may also involve questions of conduct, transparency or access rather than (or in addition to) efficient expenditure. Others may create new regulatory needs, such as greater transparency about how NSPs invest and deliver outcomes at a program level for resilience and cyber security expenditure. We consider that the ex ante framework remains appropriate for expenditure assessment purposes and could adapt to some of these needs – for example, by requiring NSPs to provide clearer information about proposed investment and the outcomes delivered.

However, there may be particular circumstances where the conditions that support effective incentive regulation are no longer present. In those cases, the appropriate response should depend on the nature of the regulatory problem. This may involve a different approach to expenditure assessment or risk allocation. Where the issue concerns conduct, access or information rather than expenditure efficiency, greater use of conduct obligations and transparency requirements may be appropriate.

For example, our information paper highlighted an emerging coordination problem, whereby efficient outcomes are increasingly dependent on coordination across diverse participants with different, potentially misaligned, interests and incentives. Applying an expenditure incentive does not necessarily solve this problem – whole-of-system outcomes are affected by the quality, neutrality or effectiveness of the coordination itself. They also depend on factors beyond an NSP's behaviour, including wholesale market conditions, other networks, generation, storage or CER behaviour. Any incentive linked directly to wider whole-of-system outcomes would require both a reliable counterfactual and a basis for attributing the resulting benefit to the NSP.

We therefore consider that the ex ante incentive-based framework should remain the starting point where the principal regulatory problem is information asymmetry about efficient costs and the NSP retains meaningful control over the relevant outcome. For emerging functions (including coordination functions), it may be necessary first to identify a more directly observable network output before an effective incentive can be designed. Any incentive should also build on a foundation of underlying conduct obligations that establish minimum expectations for the quality, neutrality and effectiveness of coordination.

Allocating risk to who can manage it best

The function of the risk allocation framework is to determine which risks should remain with NSPs to manage with the ex ante allowance and which should be transferred to consumers when circumstances change. Efficient risk allocation generally places risk with the party best able to manage or mitigate it. This allows exposure to risk to operate as an incentive for efficient behaviour, while avoiding compensation for risks that an NSP has little ability to influence.

The consultation paper noted increasing use of uncertainty mechanisms to recover costs outside of the ex ante incentive-based framework could be weakening incentives for NSPs to manage risks, potentially reducing their accountability and shifting more risk and costs onto consumers. Where a network can materially influence forecasting, procurement, solution choice or delivery, retaining appropriate exposure to that risk remains important to the operation of the incentive framework.

Ex ante incentive regulation is intended to expose NSPs to both part of the benefit of outperformance and part of the cost of underperformance. While an uncertainty mechanism allows expenditure that would otherwise attract an incentive penalty to be recovered from consumers, it can reduce or remove the downside exposure that gives the incentive scheme its force. That may be appropriate where the additional cost arises from a risk the NSP could not efficiently manage and which the framework did not intend it to bear. However, it is more difficult to justify where the mechanism effectively protects the NSP from the consequences of cost performance the incentive scheme was designed to expose it to.

The same discipline should apply to emerging coordination functions. Before a financial incentive is attached to an outcome, the framework should establish whether the network controls that outcome and whether performance can be independently observed. Where it cannot, the regulatory output may need to sit closer to the action or information the network actually controls.

We consider the existing suite of uncertainty mechanisms remains appropriate for allocating risks that cannot efficiently be managed within the ex ante allowance. However, increased use of these mechanisms makes it important to consider whether their design and interaction continue to preserve the intended allocation of risk and the incentives of the ex ante framework. We ask the AEMC to consider whether:

- the control mechanism is selected at the right stage of the revenue determination process, and whether it allocates demand risk efficiently between NSPs and consumers
- the cost pass through materiality threshold appropriately allocates risk between NSPs and consumers
- the contingent project assessment process adequately reflects the scale, complexity and risk profile of high-value projects
- the reopener mechanism retains a clear and distinct role alongside ex post review and other uncertainty mechanisms

We discuss each of these issues below.

Allocating demand risk through form of control

The form of control, or the control mechanism for direct control services, defines how NSPs set their tariffs and how they earn revenues. The NER lists several control mechanism options, including a schedule of fixed prices, price caps, revenue caps, tariff baskets and revenue yield control. These different control mechanisms entail different incentives for NSPs, with implications for their potential behaviour. Application of one or more of these mechanisms, potentially in a hybrid form, requires judgement as to what NSP behaviours would best promote the long-term interest of consumers.

We currently apply revenue cap regulation to all regulated electricity NSPs. Revenue caps remove demand risk from NSPs (because their revenue is the same regardless of how much energy consumers use), so this form of control does not incentivise NSPs to support demand growth. This has been appropriate because electricity demand growth over the longer term has been a consistent feature of Australia's energy sector and growth in peak demand is the biggest driver of network costs.

However, demand forecasting is increasingly uncertain due to growth in large loads (including data centres), the electrification of road transport and the transition of homes and businesses away from gas. While we rigorously assess NSP demand forecasts, we have incomplete information due to the information asymmetry between NSPs and regulators noted in the consultation paper. If the forecast demand increases don't eventuate, under revenue cap regulation, customers will face higher tariff levels.

Moving volume risk (or the risk that demand is lower than expected) towards NSPs could strengthen demand forecasting incentives, but it could also create a countervailing incentive to inefficiently increase network throughput. That requires particular care as electricity distribution networks take a greater role in coordinating flexible demand. The long-term interest of consumers, in respect of both price and reliability of supply, is often better served by changing the timing or profile of demand in areas of the network prone to congestion (for example, where this avoids or defers higher network or system costs) and to shift energy use and generation across the day than it is by increasing total throughput with a view to lower unit costs over time.

Any movement away from a pure revenue cap will therefore need to be considered alongside the broader incentive framework – and, conversely, any changes to the broader incentive framework should be tested under different forms of control. This could include whether an offsetting incentive for efficient demand flexibility or another regulatory treatment that preserves appropriate neutrality between additional throughput and an efficient demand-side response would be required under a different form of control. We have begun to consider these issues and interactions in the context of electricity distribution networks, including to inform future determination processes.

We currently determine the control mechanism for each electricity distribution NSP during the framework and approach stage of the revenue determination process. The NER does not give us discretion to revisit that decision. This provides predictability for NSPs and stakeholders. However, because the framework and approach is settled before we receive the NSP's revenue proposal, including its demand forecast, we cannot tailor the control mechanism in light of that forecast.

Refining cost pass through materiality

Since 2020, we have seen a growing number of weather-driven natural disasters, as well as government policy initiatives. Of itself, this does not change the risk allocation between NSPs and consumers, as these potential cost pass through events are pre-defined in the NER or our revenue determinations.

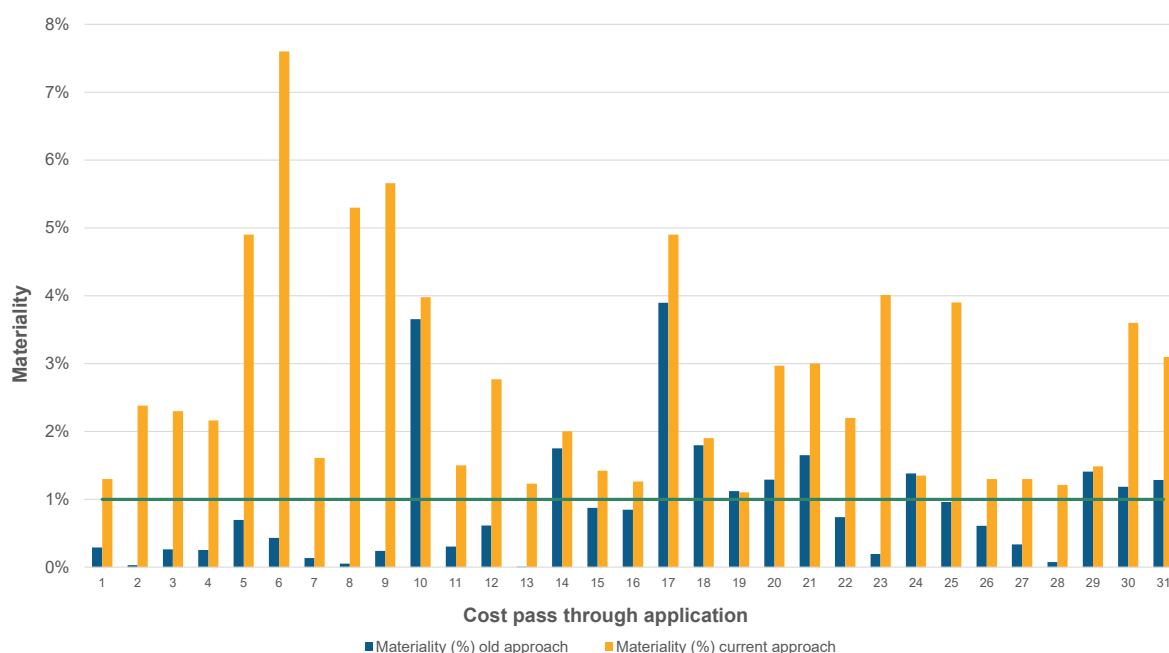
However, the number of cost pass through applications meeting the NER-prescribed materiality threshold (1% of annual regulated revenue) has also risen. This is because an AEMC rule change in 2017 altered the meaning of 'change in cost', which is used across

several NER provisions including those for cost pass throughs. In effect, this lowered the materiality threshold and therefore expanded the range of relatively small cost pass through events that are eligible under the cost pass through framework to be passed through to consumers, rather than managed by NSPs within their existing revenue allowance.³

As a result, we are seeing increased use of the cost pass through mechanism by NSPs to recover small amounts of incremental revenue. In aggregate, this may weaken the exposure to cost risk that supports efficiency incentives under the ex ante framework.

Error! Reference source not found. shows how the methodology for assessing materiality affects the number of cost pass through applications. Under the current approach applied since 2020, 31 cost pass through applications for natural disaster and regulatory change events have been assessed and approved. Under the previous approach, only 11 (35%) of those applications would have satisfied the materiality requirement and exceeded the 1% threshold which is represented by the green line in the figure.

Figure 1. Outcomes of different materiality methodologies for cost pass through applications



Assessing the materiality of the cost pass through with reference to the annual incremental unsmoothed revenue impact, rather than the actual capex and opex costs, would rebalance some risks that NSPs are currently able to pass on to consumers. However, we note this may also change the incentive between incurring opex and capex when responding to pass through events and encourage an opex bias. This is because opex has a greater immediate revenue impact, as opex is recovered in the year incurred while capex is recovered over the life of the asset.

³ AEMC, [Cost pass through arrangements for Network Service Providers, Rule Determination](#), 2 August 2012, p. 20.

An alternative may be to increase the 1% threshold and retain the current approach for calculating materiality. This would rebalance the risk sharing profile, encourage use of existing revenue allowances to manage changes in costs, and better preserve the role of cost pass throughs for material risks that cannot reasonably be managed within existing allowances.

From an administrative perspective, we also see opportunity for process efficiencies in dealing with cost pass through applications. Our August 2025 letter to the Treasurer set out regulatory reform opportunities to bolster productivity growth, including a proposal to introduce a streamlined cost pass through process for natural disasters by creating a template for top-down review and a deemed approval category.⁴ We are currently considering opportunities to clarify cost pass through application and assessment processes through guidance. However, there are more significant opportunities that would require changes to the rules.

Currently, applications must be submitted to us for assessment within 90 business days of the cost pass through event occurring. This could be adjusted to require NSP applications to be submitted on an annual basis, following each regulatory year. Batching applications in this way would create certainty on timing for us and the NSPs (enabling better resource management) and facilitate streamlined processes for duplicative or simple cost pass through assessments.

Assessing high-value projects through the contingent project framework

The current contingent project mechanism was designed to address projects that both the AER and NSP have agreed have high levels of uncertainty and could not appropriately be included in the ex ante forecast at the revenue determination stage. The AER and NSP establish triggers in the revenue determination demonstrating the need for the project, with the costs assessed once an application is submitted.

High-value contingent projects are testing a mechanism designed for projects that could not appropriately be included in the ex ante allowance because of uncertainty about their timing, need or cost. The regulatory problem these projects raise is whether the existing contingent project process provides sufficient time and information to assess efficient expenditure and allocate project risks appropriately at this scale.

Since 2020, we have received 14 contingent project applications, 10 of which relate to ISP actionable projects, and 7 of which have come from a single transmission NSP, Transgrid.⁵ The 14 applications have resulted in \$12,212 million in contingent project revenues being approved, 95% of which relates to ISP projects. The average approved cost of an ISP project was \$1,156 million, compared with \$162 million for non-ISP projects. In aggregate, approved expenditure for these projects was 12% higher than the corresponding ex ante capex forecasts.

ISP project triggers are determined by AEMO and focus on maximising system-wide benefits rather than being limited to the individual network itself. As a result, an ISP contingent

⁴ AER, [Letter to the Treasurer and Minister for Finance](#), 1 August 2025, p. 3.

⁵ These numbers include multiple applications for a single project because of staging and early works.

project is generally submitted to the AER to optimise these benefits including project delivery time. Historically, forecast costs associated with ISP projects have also been more uncertain during both early works and construction phases. This uncertainty, together with distinct delivery and timing risks, raises questions about how those risks should be allocated between NSPs and consumers. In practice, we have recognised the different risk profile by including risk allowances and modifying the application of the CESS for some ISP contingent projects. Some NSPs have also submitted applications earlier than would be typical for other contingent projects because they expect assessment to take longer.

The current mechanism requires the AER to assess all contingent project applications within 40 business days. This timeframe was more workable when contingent projects were relatively low value – it is increasingly difficult to reconcile with the scale and complexity of some high-value applications. The mechanism continues to work well for non-ISP contingent projects, but large ISP projects may warrant a different or modified approach. Their assessment is already more project-specific and, in practice, closer to a cost-of-service approach. If the existing approach is retained, there are changes that could better accommodate these characteristics. These could address the information required to assess efficient costs, the time available for assessment, the allocation of project and delivery risks, and how incentives apply. For example, the assessment timeframe for high-value contingent projects could be increased. The NSW REZ framework provides 126 business days to determine appropriate costs for REZ projects.⁶

We encourage the AEMC to examine whether the characteristics of some high-value projects, including ISP projects, warrant modifications to the current incentive-based approach or a different mix of project-specific assessment, incentives and risk allocation. Any departure from ex ante incentive regulation should be targeted to circumstances where information asymmetry cannot be addressed effectively and NSPs have limited capacity to manage the relevant expenditure risks.

Clarifying the scope of the reopener mechanism

The third intra-period adjustment mechanism is the capex reopener mechanism, which was created prior to the development of the incentive framework and was designed for situations where an NSP is obliged to invest in a major vital project (the absence of which would have material impacts on the reliability and security of the network) that would otherwise cause it to exceed its capex allowance.⁷ However, the framework has since evolved – it is no longer clear what the purpose of the reopener mechanism is or what specific problem it addresses that is not already dealt with by the combination of cost pass throughs, contingent projects and ex post reviews.

While the reopener is expressly not intended to overlap with cost pass throughs and contingent projects, there is unnecessary complexity in scenarios where a portion of a specific issue can be addressed by a cost pass through or contingent project. We consider there would be value in clarifying the purpose and scope of the reopener mechanism. This

⁶ EII Regulation, cl. 50: <https://legislation.nsw.gov.au/view/html/inforce/current/s1-2021-0102#sec.50>

⁷ Capex reopeners were introduced to the rules in 2006 (AEMC, [National Electricity Amendment \(Economic Regulation of Transmission Services\) Rule 2006 No. 18](#), 16 November 2006). The Capital Expenditure Sharing Scheme was first introduced in 2013 (AER, [Capital Expenditure Incentive Guideline for Electricity Network Service Providers](#), November 2013).

would simplify the assessment of applications and increase certainty for NSPs in being able to make urgent investments to preserve the reliability and security of electricity networks.

We are also concerned about the interaction between reopeners and the incentive framework. The existence of downside exposure to the network business under an incentive scheme is not, of itself, a reason to transfer that risk to consumers. We consider there would be value in clarifying the purpose and scope of the reopener mechanism, including how it differs from other uncertainty mechanisms.

Considering broader trade-offs in other options for managing uncertainty

Some more fundamental framework changes would also impact the risk balance between NSPs and consumers. For example, shortening the regulatory period or building an anticipatory allowance into the ex ante expenditure forecast as a revenue buffer would have significant impacts beyond risk allocation to NSPs and customers. These impacts would require careful consideration for any potential solution.

Anticipatory investment should also be considered as a risk-allocation issue. In deciding whether to support anticipatory investment, relevant considerations include the cost of investment delay, the consequences of premature commitment, whether investment can be staged or reversed, the value of information that will become available over time and who bears stranding risk. If the regulatory problem is uncertainty about whether or when an investment will be needed, the appropriate response may be a contingent or staged mechanism rather than a general allowance for earlier investment.

Efficient solutions, innovation and emerging network functions

The energy transition is changing both the choices available to networks and the functions they perform. The existing framework already contains tools intended to support efficient choices between capex, opex and non-network alternatives, but the reasons for the relatively limited use of non-network options need to be better understood before more fundamental change is pursued. Innovation raises a related but distinct issue: whether targeted support is needed where networks would not otherwise capture the wider benefits of experimentation. Emerging monopoly functions raise a different question again: whether baseline obligations, financial incentives or a combination of the two is best suited to the particular regulatory problem.

The expenditure framework could better promote efficient solution choice

The AEMC's consultation paper asks whether differences in the treatment of capital and operating expenditure influence how networks choose between otherwise efficient solutions. The existing framework addresses this through the expenditure assessment – an NSP must show that its proposed expenditure is efficient, prudent and meets the relevant expenditure criteria as set out in the NER.

That architecture provides a strong basis for scrutinising expenditure proposed by a network. It can also accommodate different ways of meeting the need driving that expenditure. Operating expenditure or a non-network solution – including where a third party invests in assets - can sometimes substitute for capital expenditure, and the framework can accommodate certain broader market benefits in investment assessments.

However, the limitations of the current framework become more apparent where operating the distribution network increases expenditure for the regulated network but reduces costs elsewhere in the electricity system. For example, a distribution NSP may incur additional operating expenditure to actively manage EV charging to reduce coincident demand on the transmission network, even where there is no distribution constraint and therefore no distribution investment to avoid. In these circumstances, the existing framework provides no clear basis for recognising the wider system value created by that expenditure.

The question of how to recognise that value is a critical one for the energy transition. As our information paper highlighted, coordination requirements are growing within networks, at the interface with competitive markets and across the energy system, but individual incentives and therefore behaviours may not align with system-wide efficiency.

One way of thinking about system-wide efficiency is through the National Electricity Objective (NEO). The NEO guides the AER and AEMC when exercising statutory functions and powers. It does not impose an equivalent obligation on NSPs to pursue system-wide outcomes. NSPs contribute to the NEO through the functions, obligations and expenditure objectives assigned to them under the regulatory framework. A broader question for Package 2 is therefore whether the framework assigns the right functions to NSPs and gives them appropriate obligations and incentives to perform those functions in a way that will promote the NEO.

The distribution capital expenditure provisions illustrate the issue. A distribution NSP's recoverable capital expenditure must meet the specified capital expenditure objectives, be incurred in providing standard control services and be properly allocated to those services. An investment may reduce total system costs, improve system security or support emissions reduction, but those wider benefits do not by themselves establish that the expenditure can be included in the NSP's forecast – the expenditure must still be linked to the functions and services the framework assigns to the NSP.

This is not an argument for giving NSPs a general entitlement to expenditure whenever they identify a wider system benefit. In some cases, the appropriate response may be to define an operating, information, access or coordination obligation that an NSP must meet without material additional expenditure. Where expenditure is required, the assessment should focus on the efficient action and costs properly attributable to the NSP, rather than the total value created across the system.

The current expenditure criteria and objectives are consistent with the NEO – they define the circumstances in which an NSP may recover expenditure in performing the functions and providing the services assigned to it. A gap may nevertheless arise where an action would promote the NEO through wider system benefits but does not fall within an expenditure objective or service assigned to the NSP. Where the action should be undertaken by the NSP, the framework may need to assign it as a function or obligation. An expenditure pathway would only be needed if meeting that obligation involved material additional costs.

How the need is defined can affect the solutions considered

The ability to compare alternative solutions also depends on the need against which they are assessed. The RIT-D can assess network and non-network options and recognise broader market benefits once an identified need has been established. The distribution NSP

nevertheless has an important role in defining that need and the technical characteristics that a credible option must satisfy. Assumptions made before the option assessment can therefore affect which solutions subsequently appear viable.

After-diversity maximum demand provides a practical example. A connection or planning assumption about coincident maximum demand can determine the capacity considered necessary. If that assumption does not adequately recognise price-responsive or flexible demand, capacity may be provided before a constraint emerges. The resulting headroom can weaken the locational signal that might otherwise support a tariff response or the procurement of flexibility. In that case, later neutrality between capex and opex would not address the earlier decision that determined how much network capacity was required.

The drivers of capex–opex choices are diverse and complex

As the AEMC notes, one potential driver of a capex bias could be where there is a misalignment between the regulated rate of return and an NSP's actual cost of capital. NSPs receive a return on capex and not on opex, but this does not mean that there is necessarily a capex bias driven by financing. The value of the capex investment over the life of the asset should be neutral to an opex equivalent option if the return on capital (set by the AER) is equal to the return on capital that the NSP actually receives through its actual cost of debt and equity. However, if:

- our allowed return on capital is greater than the true return on capital, a capex bias could exist
- our allowed return on capital is less than the true return on capital, an opex bias could exist.

Other drivers may be equally or even more important than deviations between the allowed and true cost of capital, including:

- established business practices being tied to traditional network investments
- perceived supply risk from sourcing non-network third party solutions
- perceived advantages to controlling network assets which other service operators rely on
- incentive schemes between capex and opex, which if unbalanced could result in a stronger incentive one way or the other.

Therefore, the issue is whether differences in regulatory treatment affect how a network chooses to meet an identified need, and whether NSPs favour a higher-cost solution once risk and service outcomes are considered. We think these are issues worth exploring.

It should also be noted that substitution is primarily possible for information and communications technology (ICT), as well as the use of non-network alternatives to manage consumer energy resources, provide network support and defer network augmentation.

Non-network alternatives to infrastructure investment can optimise network expenditure now and, increasingly, into the future as technologies and enabling frameworks (such as the distribution system operator) make flexibility services more abundant. As noted in the

consultation paper, the current framework already has several mechanisms to encourage prudent and efficient use of non-network options.

Some of these mechanisms apply at the proposal stage. These include the expenditure assessments conducted as part of a revenue determination, which often involves options analysis, and targeted planning obligations such as the regulatory investment tests for transmission and distribution (RIT-T and RIT-D), which provide transparency of the network options selected and opportunities for non-network options to be proposed.

Further mechanisms create incentives for actual expenditure to remain efficient. These include the CESS, EBSS and appropriate setting of a regulated rate of return through the rate of return instrument, as well as targeted financial incentives such as the DMIS. In combination, they are intended to remove undue financial bias and encourage the appropriate use of non-network options.

Despite this, the use of non-network options has been lower than may be optimal. While this is worthy of exploring, we caution against it alone being the grounds for fundamental framework changes, such as introducing a 'totex' model. A totex model should be assessed as a potential response to a defined expenditure classification distortion, and not as the answer to low uptake of non-network solutions generally.

As the AEMC considered in 2018, several factors, in addition to the financial incentives delivered by the regulatory framework, may contribute to NSPs favouring a network solution (treated as capex) over a non-network solution (treated as opex). Moving to totex would not address a capex solution preference where this is driven by an NSP's risk and asset management preferences (for example, hesitancy to adopt newer or unproven technologies, or to rely on contract agreements with non-network option providers rather than owning physical assets). Similarly, totex would not address NSP preference for capex solutions if driven by perceived opportunities to leverage ownership of physical assets to earn additional revenue from unregulated services. In the context of reviewing our Shared Asset Guideline, Essential Energy submitted:⁸

Every investment in regulated infrastructure involves choices about the technology selected, the capabilities incorporated within that asset, and the opportunities it may create throughout its operational life. Those decisions determine whether customer-funded infrastructure is capable of supporting additional services that generate enduring customer value alongside its primary network function.

Transitioning to a totex model would further require all expenditure to be considered under a revealed cost assumption. This assumption works well for opex as it allows benchmarking to occur. When benchmarking was introduced to opex, we observed significant operational efficiencies being achieved by all NSPs. Benchmarking continues to drive efficiencies in opex. This is supported by the EBSS, which is linked to the revealed cost base-step-trend forecasting approach.

Benchmarking is used as one tool to help assess capex, but this is restricted to recurrent types of expenditure (such as the use of the repex model for distribution NSPs, which tests

⁸ Essential Energy, *Submission to AER: Review of the Ringfencing guideline and Shared asset guideline*, August 2026, pp. 22–23.

unit rates and replacement timing) and non-network expenditure (such as recurrent ICT or fleet). Benchmarking or revealed cost cannot show whether most forecast capex is efficient, as most network capital projects tend to be forward looking, addressing network specific issues or constrained by NSP characteristics (customer base, topology, demand, jurisdictional obligations).

Operationalising totex as a regulatory framework would also require significant rework of the data reporting and monitoring regimes, as well as modifications to the current capex incentive scheme. The decision to move to a totex model should not be made lightly. Before doing so, we consider there is value in examining whether the existing framework can better support efficient choices between capex and opex (and non-network alternatives). In particular, the interaction between the CESS and EBSS could be reviewed to determine whether differences in the strength or timing of incentives are affecting NSPs' choice between otherwise substitutable solutions. These settings can be adjusted within the existing framework and may provide a more targeted response to any identified distortion.

A totex framework may be appropriate if the AEMC identifies a material distortion between capital and operating expenditure that cannot be addressed effectively within the existing framework. This suggests that any assessment should focus on whether there is evidence of such a distortion, and its causes, rather than the low uptake of non-network solutions alone.

Wider system benefits should inform expenditure decisions

A further question is how wider system benefits should inform regulatory decisions. Our information paper distinguishes between the value created by a coordination decision and the allocation of that value between networks, market participants and consumers. Wider consumer benefits may be relevant to the choice between regulatory solutions, but they do not determine how much of that value should be attributed to the NSP.

Network decisions increasingly affect costs outside the regulated cost base of the NSP making the decision. CER and other distributed resources provide a clear example because the benefits of more effective coordination can arise through wholesale markets, network expenditure, generation and storage investment and the actions of consumers and aggregators. These benefits are relevant to the long-term interest of consumers where they affect the price or other matters specified in the NEO. Therefore, they should be capable of informing regulatory decisions where the framework requires comparison of alternative solutions.

System benefits can be jointly produced. A network may make capability available while a retailer, aggregator, generator, storage provider or consumer incurs costs and takes the action that realises the benefit. Allocating the total benefit to the network may therefore overstate its contribution. Using the full estimated value as an expenditure threshold could also absorb the consumer surplus created by the intervention, or risk double counting if the impact of other interventions is not taken into account.

This distinction is relevant for measures such as the Customer Export Curtailment Value. A value placed on additional export capabilities can reveal important information about the benefits of improving that capability. However, this should not be treated as an expenditure envelope within which network investments remain efficient. Alternative ways of providing

that capability, costs to market participants and the benefits retained by consumers remain relevant.

The NSP may also hold information about available capacity, constraints and operating conditions that materially affects the estimated counterfactual. A mechanism that rewards the NSP according to wider system benefits calculated using those assumptions would place considerable weight on information supplied by the party whose regulated revenue depends on the result.

Costs and benefits arising elsewhere in the electricity system can therefore inform solution choice without automatically determining network expenditure or reward. Where an emerging network function is not anchored to an investment decision, the framework may instead need to identify the action or output attributable to the NSP that can be independently assessed.

Promoting innovation is important to achieving an efficient energy transition

Decentralisation and digitalisation are creating new ways to respond to needs previously addressed through physical network investment, while increasing the importance of platforms and coordination. However, the pace at which new technologies, services and business models are emerging may not align with some expectations and the requirements of an inverter-based renewable energy system.

This does not, by itself, establish why efficient innovation may be failing to occur or which regulatory response would be appropriate. As our information paper highlights, the framework must respond effectively to distinct regulatory issues – for example, it must distinguish between monopoly, coordination, access and innovation problems rather than treating the transition as a single regulatory problem.

The Demand Management Innovation Allowance Mechanism (DMIAM) and Demand Management Incentive Scheme (DMIS) were intended to spur NSP innovation, but uptake has been limited. The reasons for this are unclear. It could relate to the strength of the financial incentive, to the eligibility criteria, to NSP cultural issues or simply to a preference to pursue financing for innovative projects through the business-as-usual revenue determination process instead.

More fundamentally, these schemes may not directly or sufficiently address the barriers to innovation. Given different barriers may warrant different responses, it is useful to consider why efficient innovation would not occur. For example, it may be because:

- knowledge generated through experimentation may benefit other networks, consumers or the regulatory framework more broadly while the network undertaking the trial bears the cost and risk (positive externalities), reducing its incentive to undertake trials with wider system benefits
- costs may be incurred in the current regulatory period while material benefits arise in later periods, limiting the extent to which the network can capture the benefits needed to support the initial expenditure
- existing regulatory requirements may prevent a new technology, service or business model from being tested, requiring temporary regulatory relief and, in some cases, a corresponding pathway to fund the trial.

Our regulatory sandboxing mechanism can help address the third barrier by providing one alternative regulatory pathway for innovative projects. However, the sandboxing framework is not specifically focussed on incentivising or funding trials of new technologies or commercial initiatives related to technological deployment.

There may be merit in exploring a closer relationship between innovation funding and the regulatory sandbox. This could allow regulatory flexibility and any targeted innovation support to be considered together, particularly where a trial tests both a new technology or business model and the operation of the regulatory framework itself.

The Ausgrid Community Power Network trial illustrates this limitation because the AER was able to grant relief from ring-fencing requirements but could not use its trial waiver powers to reopen the distribution determination to provide additional trial funding. Reform could therefore consider a specific sandbox-linked expenditure mechanism, allowing tightly bounded trial expenditure to be approved outside the normal reset cycle, where the trial is designed to resolve a material regulatory question.

We have considered some alternatives to the DMIAM and DMIS to enable innovation while limiting NSP regulatory burden. In our August 2025 letter to the Treasurer setting out regulatory reform opportunities to bolster productivity growth, we committed to consult publicly on changes to network expenditure allowances to boost the efficiency of investment, including an annual 0.5% productivity growth adjustment to capex forecasts for network businesses (consistent with the factor currently applied to opex) and a standard innovation allowance (as percentage of Maximum Allowed Revenue) for all electricity NSPs with no ex ante proposal and assessment required under a ‘use it or lose it’ funding arrangement.⁹

We have established ex ante innovation allowances in recent revenue determinations, following standard public consultation processes. Providing these allowances to networks in their revenue determinations reduces regulatory burden compared with the more administratively intensive incentive-scheme approach. A rule change is not required to continue this approach, though it would provide certainty for NSPs and stakeholders.

Distribution System Operator (DSO) functions may require a different mix of obligations and incentives

The coordination problem identified in our information paper is particularly visible in distribution networks. Distribution NSPs increasingly make decisions about connections, access, operating envelopes, available capacity and constraints that affect how retailers, aggregators and consumers can use resources connected to the distribution system. The first question is which functions necessarily sit with the distribution NSP because of its control over network infrastructure, information or access, and which could be performed competitively or by another party. The allocation of the function should precede the choice of regulatory instrument.

That question is part of a broader coordination issue across network boundaries. Transmission decisions can likewise affect generation dispatch, congestion, curtailment, storage operation, system security and future investment across the NEM. The ISP provides

⁹ AER, [Letter to the Treasurer and Minister for Finance](#), 1 August 2025, p. 5.

an independent system-planning framework for major transmission investment rather than relying solely on an individual transmission NSP to identify and value wider system effects. The relevant functions and institutional arrangements differ between transmission and distribution, but in both cases the regulatory framework needs to distinguish decisions that can be governed through an individual NSP's expenditure assessment from coordination, access or operating functions that require another form of oversight.

Once responsibility for a function is clear, the regulatory treatment can follow. Requirements that are foundational to the monopoly network role (such as transparent information and clear, non-discriminatory access arrangements) may be better established through obligations or minimum standards. Financial incentives may have a role where additional effort can improve a measurable outcome and the network has meaningful control over that outcome.

Firm and flexible access provides a practical link between function allocation and network planning. The level of capacity a network needs to provide depends in part on the access it is required to support. If customers are assumed to have firm access at all times, the network may need to plan and invest to meet that level of demand. Where some demand or generation can instead be provided on flexible terms, periods of constraint may be managed without augmentation.

Access, planning and expenditure incentives therefore need to work together. The planning framework should make clear the access assumptions underpinning forecast network needs and how flexible access and demand-side responses have been considered before additional expenditure is proposed. This affects both the efficient operation of existing capacity and whether new capacity needs to be built.

The same considerations shape efficient network utilisation. Increasing throughput should not be an objective in itself – spare capacity may support reliability or resilience, while shifting or reducing demand and generation at a constrained time may lower costs even though throughput falls.

Existing regulation can recognise utilisation value relatively readily where flexibility avoids or defers an identified investment. We encourage the AEMC to consider efficient utilisation across the investment and operating decisions that determine how network capacity is provided and used. This includes the relationship between firm and flexible access, the assumptions networks make when forecasting future capacity requirements, and the incentives to use existing capacity and flexible demand before augmenting the network.

This also needs to be considered alongside form of control. As discussed above, moving demand risk towards distribution NSPs could improve demand forecasting incentives, but could also increase the financial value of additional throughput. That may be undesirable where the efficient response to a local network constraint is to shift or reduce demand, or generation. Any change to form of control should therefore consider its interaction with the incentives on NSPs to use flexibility efficiently.

Network tariffs are relevant to efficient use but should not be expected to communicate the full value of an action across the electricity system. Wholesale and retail signals also affect participant behaviour.

Revenue determination process

The revenue determination process can be improved at three connected stages. The framework and approach (F&A) stage can be narrowed to matters that genuinely need to be settled before a proposal is lodged. The statutory determination process can be made less prescriptive and more adaptable to the issues raised by each proposal. Within that process, greater emphasis on the quality and evidentiary basis of initial proposals could reduce avoidable regulatory burden. Clarifying expectations in relation to consumer and stakeholder engagement could also improve the quality of regulatory proposals and ensure stakeholders see the value of their engagement. The following sections address each opportunity in turn.

A more flexible revenue determination process will achieve efficiencies and focus effort where it will have most impact on consumer outcomes

We agree with the AEMC that significant resources are invested by NSPs, the AER and stakeholders in the revenue determination process. Based on our extensive experience in administering the current revenue determination process, we consider there are opportunities to reduce complexity and costs, better target high-value issues, and better support stakeholder input into NSP revenue proposals.

The earliest phase of the statutory revenue determination process is the F&A paper. For an upcoming regulatory period, an F&A paper for electricity transmission NSPs sets out our intended approach to incentive schemes, depreciation and application of our Expenditure forecast assessment guidelines. An F&A paper for electricity distribution NSPs sets out those positions, but also our intended service classifications and the form of control we intend to apply for the upcoming regulatory period.

The administrative process to replace an existing F&A paper for a specific NSP initiates 32 months before the first day of an upcoming regulatory period, with the NSP requesting a new F&A. While a new F&A is optional under the NER, NSPs routinely request a new F&A ahead of each upcoming revenue determination. We have adopted the practice of releasing a preliminary F&A paper to facilitate stakeholder views through written submissions before finalising the new F&A paper 23 months ahead of the upcoming regulatory period.

As noted in the consultation paper, much of a distribution NSP F&A and most, if not all, of a transmission NSP F&A is repetitive across regulatory periods. We routinely apply the most recent iteration of incentive schemes, depreciation is consistently straight-line, and we apply our Expenditure forecast assessment guidelines within each revenue determination we undertake. We see service classification and the form of control as embodying most of the value provided by the F&A, as these regulatory settings can vary over distribution NSPs and over time.

Stakeholder engagement with the F&A process is limited. On average, we receive one submission in response to our notice calling for stakeholder views on whether to replace an existing F&A. Stakeholder engagement with preliminary transmission NSP F&A papers is also limited, averaging one submission received. While counting submissions alone tells us little about the quality of an engagement process, in this case our experience suggests that these numbers are indicative of the low value placed on the transmission NSP F&A by stakeholders. Engagement with preliminary distribution F&As is more significant, averaging 8 submissions (which tend to focus on service classification).

Within the statutory F&A process there is significant prescriptive detail setting out when and how we must take specific actions. In reconsidering the F&A, we encourage the AEMC to consider a less prescriptive process to provide the necessary clarity for distribution NSPs and stakeholders on service classification and the form of control. Other F&A matters may be dealt with through alternative published AER guidance applicable over multiple NSPs and regulatory periods.

Noting the rate of sectoral change that we, NSPs and stakeholders are now experiencing, our submission to the AEMC's Package 1 consultation paper noted there may be need for the opportunity to undertake a mid-period service classification changes. Similarly, the F&A currently locks in our form of control decision in advance of receiving an NSP's initial revenue proposal, potentially undermining one opportunity to support the quality of distribution NSP demand forecasts, as noted above.

A more principles-based and agile revenue determination framework could promote efficiency through flexibility while retaining transparency

Following establishment of a new F&A, the NER sets out the ex ante propose–respond revenue determination process. While highly prescribed and inflexible, regulatory outcomes achieved to date through the existing framework have been balanced and robust, aligning strongly with the NEO and the long-term interests of consumers. However, as the consultation paper noted, the process is also resource intensive. The administrative workload and associated costs incurred by NSPs and the AER are significant and ultimately borne by consumers.

We support the AEMC reviewing the revenue determination process to achieve efficiencies, promote good regulatory outcomes and enhance stakeholder input. A key opportunity to achieve these outcomes is to reduce the level of prescription. Throughout the existing statutory process, the AER is given significant direction at levels of detail which now, 20 years after the AER's founding, appear anachronistic.

We note too that since the first version of the NER took effect on 1 July 2005, more than 250 further versions have been released by the AEMC (at time of writing, we are using version 254). This means an average of one new version of the NER has been released each month since its commencement. We suggest the level of prescription may be one driver of such frequent updates.

A further example of the level of prescription in the current framework is that in making a revenue determination, we are required to make 27 separate constituent decisions. Removing prescription and moving towards a more principles-based framework would support process efficiencies, while also supporting good regulatory outcomes in the long-term interest of consumers.

The existing two-stage statutory process of an initial proposal and draft decision, followed by a revised proposal and final decision, lacks flexibility. A revised proposal and final determination is required regardless of whether our draft determination accepts an NSP's initial revenue proposal or substitutes significant elements with our own forecasts.

Moreover, revised proposals tend to be broader than just the issues we identified with an NSP's initial proposal. This raises issues for incentives, transparency, engagement and decision-making. As a result, our draft and final decisions are also broad, incorporating total

revenue determinations and revenue smoothing, in addition to regulatory settings on specific issues. This is necessary under the existing two-step framework, as the NER requires both draft and final revenue determinations to encompass all 27 constituent decisions.

At this early stage of the AEMC's review, we do not have fixed views on the key features of a revised revenue determination process, but we see greater flexibility and less prescription as characteristics of a preferable framework. A more principles-based approach could establish higher-level obligations for the AER to assess an NSP revenue proposal and, if we are not satisfied that it best contributes to the long-term interests of consumers, to make a preferable decision. A revised framework could also reduce regulatory duplication by recognising that the AER has obligations under administrative law that need not be replicated, such as giving NSPs a right of reply and considering stakeholder views.

We welcome further engagement with the AEMC on how a less prescriptive, more principles-based revenue determination process could work to reduce regulatory burden, promote efficiency and support outcomes in the long-term interest of consumers.

Greater primacy for initial proposals could strengthen incentives and improve the determination process

NSPs are diverse and the quality of revenue proposals submitted to us varies. However, our experience is that some NSPs use their initial proposals to frame their subsequent revised proposals, leaving us to seek evidence for their initial proposal with our analysis and information gathering through the revenue determination process. This approach means the revenue determination process itself must do more work than it was designed for, with the regulator using resources to gather relatively core supporting information, such as a cost-benefit analysis or business case, before we can focus on marginal or contested issues.

This has broader consequences than regulatory workload, for both the AER and for stakeholders. If an NSP can materially develop its case through the revised proposal, the incentive to put forward its best evidence and position at the outset is weakened. It also means consumers and other stakeholders may engage with an initial proposal that changes materially later in the process, reducing the transparency of the proposal on which the final determination is made.

We consider the revenue determination process should place greater weight on the quality and completeness of the initial revenue proposal.

In terms of the information asymmetry between NSP and the regulator noted by the consultation paper, we currently address that through our analysis and information gathering. Release of our Better resets handbook in 2021 set out an early signal pathway as an incentive for NSPs – an abbreviated revenue determination process on key issues if the NSP could meet specified criteria.

While NSPs initially indicated strong interest in the early signal pathway, NSP eligibility for it is premised on expenditure proposals varying only incrementally from past practice. In the electricity network sector's current phase of growing capital and operating expenditure proposals, qualification for the early signal pathway is less likely and there have been no suitable applicants since 2024.

Internationally, there are examples of regulatory bodies providing financial incentives to elicit better quality proposals from regulated utility providers. We are open to considering financial incentives should there be a sufficiently strong case with appropriate risk mitigations for customers who will bear the cost of financing incentive payments to NSPs.

There is also opportunity to further standardise NSP revenue proposals to promote appropriate evidencing and achieve process efficiencies. We have taken steps in this direction with our standardised capex and opex models. However, more broadly each NSP currently presents revenue proposal information as it chooses. The resulting proliferation of NSP approaches promotes gaps in supporting explanatory material and supporting analysis which we must address within our assessment process when we could instead be assessing the merits of the highest value, or most contentious, matters raised.

The use of AI offers a potentially accelerated pathway to achieve greater standardisation and better quality NSP revenue proposals. We seek the AEMC's support to pursue these opportunities.

The sector's integration of consumer and stakeholder views has matured significantly – the opportunity now is to clarify and build on this foundation

As the consultation paper highlights, the sector's integration of consumer and stakeholder views into the revenue determination process has matured significantly, reflected in culture change across the NSPs. This is the result of a long journey, with key milestones along the way.

- In 2013 we established the independent Consumer Challenge Panel (CCP), whose objective is to provide independent and expert advice on issues important to consumers in regulatory proposals by network businesses and to constructively challenge the AER so that regulatory determinations are made in the long-term interests of consumers.¹⁰
- The 2017 abolition of limited merits review has meant that NSPs now focus on AER determinations instead of what had become a routine appeal to the Australian Competition Tribunal.
- Over 2018 to 2021 we worked with Energy Networks Australia and Energy Consumers Australia to jointly trial the New Reg approach to engagement.
- Our Better resets handbook (2021) has highlighted the importance we place on consumer and stakeholder engagement in shaping NSP revenue proposals.

This journey has improved NSP stakeholder engagement practices and therefore the quality of NSP revenue proposals. Consumer engagement informing NSP revenue proposals provides important supporting evidence on how well proposals align with consumer interests and expectations for price and service outcomes. The extent to which an NSP's revenue proposal addresses the concerns of stakeholders, as identified by the distribution NSP in its engagement, is one factor we have regard to in assessing NSP revenue proposals.

Stakeholder and consumer engagement cannot substitute for prudence and efficiency tests, or other assessment criteria set out in the NER or in AER-published guidance. However, it

¹⁰ AER, [AER Consumer Challenge Panel](#), 12 February 2013; AER, [CCP Terms of reference](#), July 2026.

can and does inform our assessment. Consumer perspectives can be particularly helpful in informing choices that can't be resolved by prudence and efficiency tests, including choices about service levels and cost and risk allocation.

Challenges arise when NSPs rely too heavily on the views elicited through their stakeholder and consumer engagement programs to justify expenditure proposals, without sufficiently justifying the prudence and efficiency of these proposals. This is especially concerning where engagement does not present the full suite of potential solutions to an identified problem, instead providing a relatively narrow choice of paths forward for consumers to select from. As a result, stakeholders engaged by NSPs may not see the value of that engagement if the AER does not approve proposals they have supported.

We are taking steps to clarify how stakeholder and consumer engagement can effectively contribute to the development of revenue proposals by NSPs, in the context of the Better resets handbook and the early signal pathway.

We support the AEMC review further clarifying the purpose of stakeholder and consumer engagement in the network regulation framework, as well as the roles and responsibilities of NSPs, their consumer advisory groups and the AER in that context. This could improve regulatory certainty and simplify the framework. NSPs should have clear obligations to engage transparently and in a way that enables consumers to meaningfully contribute to network expenditure decisions. Consumers and consumer representatives should have clarity about the purpose and impact of their engagement. And the AER should have a flexible and fit-for-purpose framework for assessing and considering how stakeholder and consumer engagement has informed revenue proposals, which can adapt to changing techniques, technologies, scale of expenditure and better practice.

Such a framework should recognise the value of stakeholder and consumer perspectives in informing economic regulation. For example, consumer voices can provide significant insight into the allocative efficiency of regulatory outcomes – are resources being invested in the products, services and outputs that customers value? At the same time, the framework should reflect the fact that these consumer voices complement and inform but do not (and should not) replace regulatory assessment of the prudence and efficiency of investment.

The AER's framework for consumer engagement in the Better resets handbook was drawn from the consumer engagement framework first developed for the 2021–26 revenue determinations for the Victorian electricity distribution networks. It replaced the earlier 2013 Customer Engagement Guideline. Our expectations on consumer engagement are principles-based and build on our current learnings. They cover the nature of engagement, the breadth and depth of engagement and clearly evidenced impact of this engagement.

There is an opportunity for the AEMC's review to engage with stakeholders and consumers on how the AER's framework could be adapted and matured, given that network businesses have established ongoing consumer consultative councils as well as reset advisory groups and frequently invest in consumer research and consumer panels to inform their decisions and provide accountability for the impact of their expenditure.

There are also examples to be drawn on from other regulatory settings.¹¹

We look forward to engaging with the AEMC further on how the regulatory framework could clarify the purpose and expectations of NSP stakeholder and consumer engagement, as well as how we as the regulator will consider this engagement in forming views on revenue proposals.

¹¹ For example, the Water Industry Regulatory Order 2014 which sits within the broader context of the Water Industry Act 1994 (Vic) and the Essential Services Commission Act 2001 (Vic) requires the Essential Services Commission to issue a Guidance Paper to water businesses setting out its approach to each price review which includes expectations regarding consumer engagement. That guidance includes a set of principles to guide stakeholder engagement undertaken by regulated water businesses as well as the criteria it uses to assess that engagement; Essential Services Commission, [2028 Water Price Review: Guidance](#), 15 September 2026, pp. 32–34. The Essential Services Commission also establishes expectations for water business to report annually on their performance against commitments to customers, which help consumers see whether they are ‘getting what they paid for’ and provides a mechanism to monitor the timeliness of investment; Essential Services Commission, [Water business outcomes reporting](#), 2026.