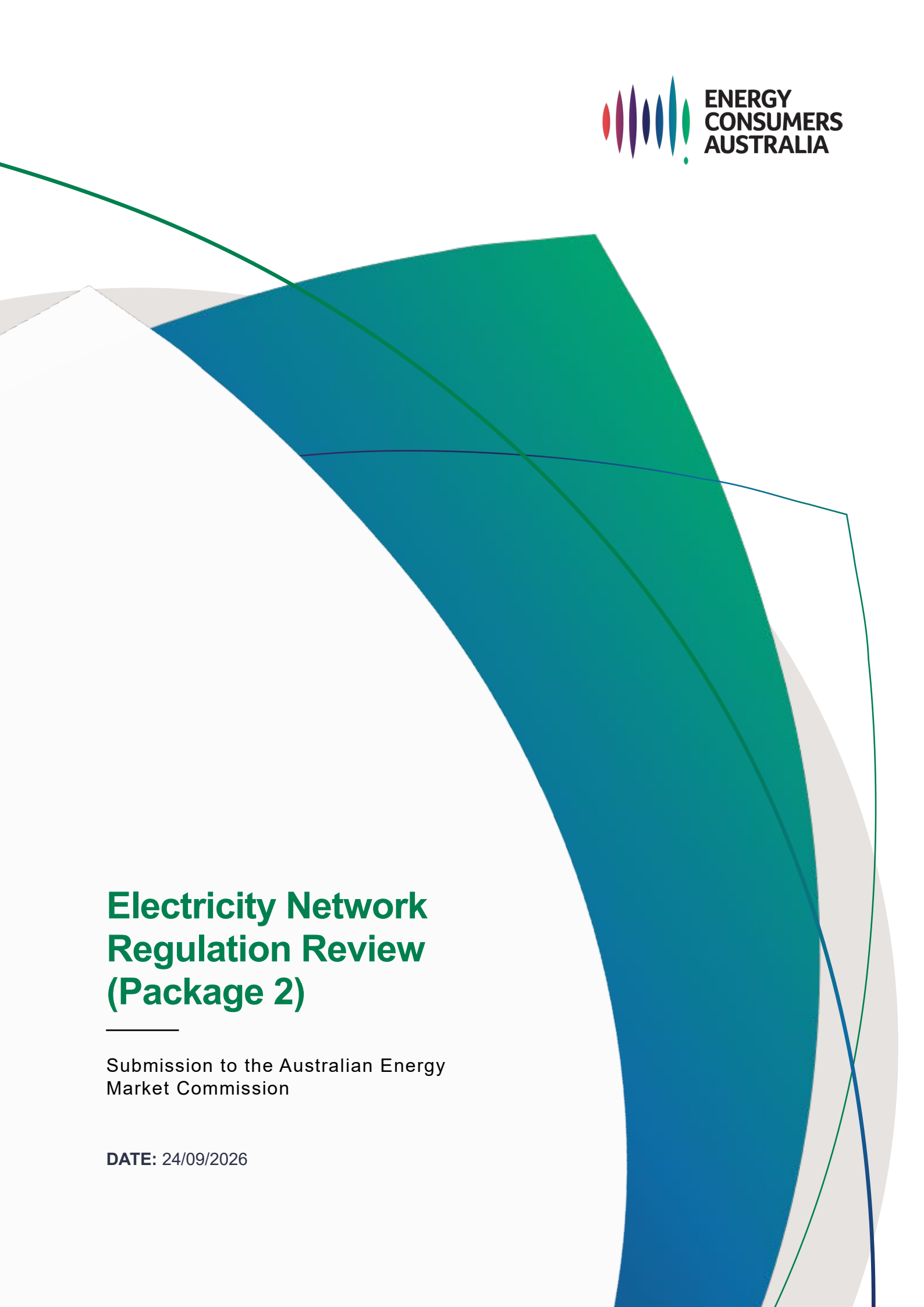
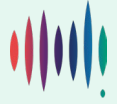


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Electricity Network Regulation Review (Package 2)

Submission to the Australian Energy
Market Commission

DATE: 24/09/2026



Cover Letter

Dear Anna,

Energy Consumers Australia (ECA) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) Electricity Network Regulation Review (Package 2).

As the national voice for household and small business energy consumers, we advocate for a fair, affordable, and reliable energy system—one that meets everyone's needs and leaves no one behind on the journey to net zero. In the context of this consultation, it means ensuring that future network regulation is balanced, allowing investments to be right-sized and consumer voices to shape network proposals.

Package 2 provides a key opportunity to embed a clear procurement sequence — no-cost, then low-cost, before any cost is added to the regulated asset base — so that network augmentation becomes a genuine last resort, with greater reliance on consumer energy resources (CER)/distributed energy resources (DER) and demand-response where these can deliver lower cost outcomes and greater resilience for consumers. We set out this 'merit order' in more detail in the accompanying report. The current regulatory framework fundamentally lacks symmetry, prioritising network augmentation over alternative procurement options which results in costly infrastructure upgrades ultimately borne by consumers. We believe that network regulation requires a conceptual shift, moving away from a model that is organised around determining how much efficient expenditure a network needs and providing revenue to recover that expenditure, toward one that defines the specific network services that consumers need and identifies the least-cost way to deliver these.

Jurisdictions overseas have already paved the way, and we believe that adopting similar practices will enable procurement decisions to be driven by consumer and system needs, therefore avoiding unnecessary capital expenditure on traditional network augmentation when flexible, non-network solutions offer a more efficient path forward.

Redefining incentives to elevate non-network options in procurement decisions

While much of the debate has revolved around whether the current framework creates a bias towards capital expenditure and a risk of gold plating,¹ our more nuanced view is that the current incentives do not adequately support the procurement of non-network alternatives. Research conducted by Energeia goes even further, stating that the “*existing incentive schemes are doomed to fail*”² because capital expenditure increases shareholder returns by 200% compared to the best performing non-network incentive.³ This creates a major imbalance, and a huge missed opportunity: non-network alternative accounted for 0.1% of total network spending,^{4, 5} despite evidence suggesting that up to 25% of all network expenditure could be replaced with non-network investments, thus reducing costs by up to \$27 billion over the next 30 years.⁶

This is all the more concerning that the nature of the risks we are facing is changing, with climate change already leading to worsened weather events, a trend that will continue over the long-term.⁷ This also

¹ IEEFA, 2024 – [Reforming the economic regulation of Australian electricity distribution networks](#), pp. 26-28

² Energeia, 2022 – [Are electricity network incentive schemes rewarding the wrong behaviour?](#)

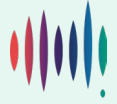
³ *Ibid.*

⁴ *Ibid.*

⁵ Energeia, 2021 – [Renew DER Optimisation \(Stage II\): Final Report](#), p. 12

⁶ Energeia, 2022 – [Are electricity network incentive schemes rewarding the wrong behaviour?](#)

⁷ NSW EPA, 2023 – [Increasing frequency and intensity of extreme weather events](#)



means that we may need to reconsider what constitutes a ‘normal risk’,⁸ especially at a time when overcoming our traditional reliance on poles and wires investment is essential.⁹

Additional network infrastructure investment can make equipment more robust, but it won’t necessarily improve resilience.¹⁰ It can, however, increase costs for consumers.¹¹ A more resilient approach therefore requires networks to consider a broader portfolio of solutions, including CER, DER, demand response, and other flexible resources that can reduce exposure to network failures and increase consumer resilience.¹²

Yet, the current regulatory framework does not provide sufficiently strong incentives for networks to identify, develop, and procure these alternatives. The Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism are not enough to overcome the lack of market development at scale that prevents non-network options from “*meet[ing] the criteria of being commercially and technically feasible as an alternative to improve resilience*”.¹³

In this regard, lessons can be learned from overseas jurisdictions, notably the European Union and the UK, where procurement of flexibility and other non-network solutions is increasingly embedded in regulatory and market frameworks.^{14,15} These jurisdictions have supported the development of procurement markets, creating stronger pathways for non-network options to compete with traditional network investment.¹⁶

Therefore, the question isn’t so much about whether options are available—they are—but whether the regulatory framework creates the right conditions for networks to procure them.

Rebalancing the incentive framework by introducing more explicit penalties

We see a need to rebalance the broader regulatory framework by introducing clearer, more explicit penalties that mirror existing financial incentives. The consultation paper itself describes the range of incentives intended to deliver particular outcomes rather extensively but barely mentions penalties.¹⁷ We expand on this imbalance, including the case for symmetric reward-penalty mechanisms, in the accompanying report.

We believe this raises a key question about the role of electricity networks and what should be expected from them. If we *do* consider electricity an essential service—and one that could be seen as a fundamental consumer right—^{18, 19} then there is a need to clearly define what constitutes ‘standard’, baseline network behaviour. This would allow us to more clearly identify poor performance, as well as above-and-beyond behaviour, and establish regulatory rewards and penalties accordingly.

⁸ AEMC, 2026 – [Electricity Network Regulation Review – Package 2 Consultation Paper](#), p. 74

⁹ enX, 2026 – [Demand management incentive schemes for networks](#)

¹⁰ Erne Energy, 2024 – [Consumer Electricity Resilience](#)

¹¹ Erne Energy, 2026 – [Network resilience guidelines – Consultation paper](#), p. 5

¹² Erne Energy, 2024 – [Consumer Electricity Resilience](#)

¹³ Essential Energy, 2025 – [Risk Based Proactive Pole Replacement](#), p. 4

¹⁴ IEEFA, 2024 – [Reforming the economic regulation of Australian electricity distribution networks](#), pp. 40-46

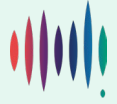
¹⁵ [Regulation \(EU\) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity \(recast\)](#)

¹⁶ IEEFA, 2024 – [Reforming the economic regulation of Australian electricity distribution networks](#), pp. 40-46

¹⁷ AEMC, 2026 – [Electricity Network Regulation Review – Package 2 Consultation Paper](#). “Incentive/incentives” returns 380 occurrences, compared to 19 for “penalty/penalties”

¹⁸ Erne Energy, 2024 – [Consumer Electricity Resilience](#)

¹⁹ ECA – [Community Energy Congress](#), p. 13



In comparison, jurisdictions like Germany, have introduced a ‘bonus-penalty’ system that incentivises networks to reduce costs, while also penalising those that would deliver below-average quality of service.²⁰ This ensures that while networks are encouraged to reduce costs, those cuts do not happen at the expense of service quality or necessary investment.²¹ In the UK, the issue has been addressed through Ofgem’s RIIO (Revenue = Incentives + Innovation + Outputs) framework, under which networks are responsible for delivering a high quality of service and meeting specific performance targets. Failure to deliver those outputs can be met by a variety of measures, including financial penalties, and claw back of revenues.²²

Ultimately, we believe that incentives/rewards and penalties should be considered as two sides of the same coin. Where networks receive a financial incentive for achieving a particular outcome, that is, above-and-beyond the baseline, there should be a corresponding penalty when that outcome is below par. This requires making clear which outcomes are core obligations.

A different approach to consumer engagement may be warranted

Consumer engagement should be another cornerstone of this review. In fact, we believe there is a case for incorporating consumer voices at the beginning of network planning and determination processes, rather than once they’ve already started.²³

We acknowledge the inherent tension between the complexity of network regulation and consumers’ ability to make informed decisions about network investment and long-term operations—it would be delusional to suggest that consumers could, or should, substitute for technical experts. We firmly believe, however, that those processes would benefit from consumers directly informing and shaping them from the outset.

While a number of consumer panels exist, we believe there is also value in including everyday consumers more comprehensively in those conversations. The French Citizens’ Convention on Climate provides an example of what this could look like. In 2019-2020, 150 citizens were randomly selected to develop climate policy proposals to reduce greenhouse gas emissions.²⁴ Participants were selected to reflect the diversity of French society, in terms of socioeconomic background, education level, geographic spread, etc., and were supported by independent technical and legal experts.²⁵

A similar model could be envisaged in the context of network determination. Consumers would be randomly selected to form a representative group, be given time to familiarise themselves with the issues, and develop proposals with the support of technical, economic, and legal experts. The outputs would then guide the development of the final network proposals.

This would give those who pay for and rely on the networks an opportunity to weigh in the conversation, while making network determination, and the broader energy space more participatory and transparent.

Conclusion

We have provided detailed responses to the questions posed in the consultation paper via the report attached. It focuses on the role of risk in the existing regulatory framework, demonstrating that networks are risk resistant. The existing risk-reward balance discourages the innovations in energy technology that

²⁰ CEER, 2025 – [Regulatory Frameworks for European Energy Networks 2024](#), p. 60

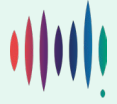
²¹ *Ibid.*

²² *Ibid.*, pp. 62-63

²³ JEC, 2017 – [A guide to consumer participation in electricity pricing and revenue determinations](#)

²⁴ Convention Citoyenne pour le Climat – [The Citizens’ Convention on Climate, what is it?](#)

²⁵ *Ibid.*



have been embraced by consumers and that could reduce network costs from playing a more starring role in the provision of network service.

We encourage the AEMC to prioritise ambitious reforms that demonstrably rectify the balance within the existing network regulatory framework and prioritise long-term, cost-efficient and resilient investments.

We look forward to working collaboratively with the AEMC as they progress this important work on behalf of consumers, networks, and the broader energy system.

For further information about our submission, please contact Pauline Ferraz at pauline.ferraz@energyconsumersaustralia.com.au

Yours sincerely,

Brendan French

CEO, Energy Consumers Australia

**The national voice for residential and
small business energy consumers**



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Electricity network regulation – issues for the transition

Energy Consumers Australia

September 26



Contents

1	Executive Summary	3
2	Introduction	3
3	Risk is the key driver of regulatory outcomes	4
3.1	Risk has increased since the framework was introduced	5
3.2	NSP attitudes to risk.....	6
3.3	Risk and the rate of return.....	7
3.4	Risk aversion and a preference for control	10
3.5	Risk and innovation	11
3.6	Implications for future approaches to network regulation	11
4	Asymmetry	13
4.1	Benchmarking	14
4.2	Trend, step, change	15
4.3	Pass-throughs and re-openers.....	16
4.4	Contingent projects	16
4.5	Forecasting incentives	18
4.6	Expenditure outcomes	19
4.7	Implications for future approaches to network regulation	20
5	Incentives	20
5.1	Cost incentives	20
5.2	Other incentives.....	22
5.3	Implications for future approaches to network regulation	24
6	Engagement.....	24
6.1	Issues with current model.....	25
6.2	Implications for future approaches to network regulation	26
7	Appendix A: Implications of this report for the Package 2 Consultation paper.....	27
	Appendix B: tools for measuring network systematic risk.....	32



1 Executive Summary

This report asks whether the current regulatory framework for electricity network service providers (NSPs) remains fit for purpose as the energy transition reshapes demands on the network. Its central finding is that the framework was built on the premise that NSPs are low risk businesses, and largely continues to treat them that way even as they face a new set of risks - including asset stranding, unprecedented transmission investment, extreme weather, and large new loads such as data centres. The framework continues to insulate NSPs and their investors from most of these risks. That risk does not disappear: it is transferred to consumers, who have little practical ability to manage it, and who increasingly experience it as sustained increases in network charges.

NSPs and their owners prefer a low risk framework and are likely to resist reforms that expose them to materially greater risk, even where higher returns are on offer in exchange. This risk aversion manifests as a preference for direct ownership and control of the assets that meet system needs, rather than sharing risk with consumers or third parties.

This preference for control, combined with the information asymmetry inherent in the propose-respond model and cost incentives that continue to favour capex over opex, has produced persistently low uptake of non-network options (NNOs). Despite very high levels of consumer energy resources (CER) penetration, non-network solutions are rarely selected through RIT-T and RIT-D processes, and mechanisms intended to encourage their use, such as the Demand Management Incentive Scheme, do not appear to have been effective. Greater use of non-network options - through demand-side participation, flexible connection agreements, and third-party service provision - represents one of the most significant untapped opportunities to reduce network costs and improve outcomes for consumers, but realising it requires addressing the risk allocation that currently discourages NSPs from pursuing it.

The report also identifies weaknesses in consumer engagement, the main channel through which consumer preferences reach the regulatory process. Engagement suffers from the same information asymmetry as the wider framework: the AER has limited capacity to test or validate what networks put forward, and the regulatory timetable leaves little room for genuine dialogue before a final proposal is locked in.

Two broad ways forward are set out. The first is to increase NSP accountability and risk exposure directly, so that networks and their investors bear more of the consequences of their own investment and service delivery choices, potentially for higher allowed returns. The second is to impose more directive requirements on NSPs, including a proposed "merit order" that would require non-network options to be tested and preferred ahead of new network capex before augmentation is approved. Either way, addressing the current allocation of risk is a precondition for meaningfully increasing the use of non-network options and better aligning network investment with the interests of the consumers who pay for it.

This directive approach already has precedent overseas. Germany's regulator requires networks to enable curtailment of household batteries, EV chargers and heat pumps in exchange for a mandated tariff discount, and several US state commissions require utilities to procure a specific volume of storage and demand flexibility rather than treating it as discretionary. California's interconnection rules impose the same enforceable control standard on every battery and EV charger in the state. Australia's frameworks have so far avoided this degree of specificity, and the consumer cost of that gap is one focus of this report.

2 Introduction

Rising cost of living has put network costs under sustained scrutiny. On the AER's own reporting, network costs per customer are broadly comparable in real terms to where they stood around 15 years ago,¹ though this average conceals a widening spread: customers with consumer energy resources (CER) have increasingly been able to reduce their exposure to network charges, while those without CER bear a growing share of the same underlying cost base. The energy transition is expected to place further upward pressure on network costs over the coming decade.

¹ AER, Network performance report 2026, July 2026, p. 13

Networks have, on the whole, benefited financially under the current framework. In 2025 alone, NSPs earned \$506 million in incentive revenues, an increase of 28 per cent on the previous year,² and rewards from incentive schemes have, on a weighted average basis, delivered returns 0.8 percentage points above allowed levels over the past seven regulatory years.³ It is not obvious that this financial performance has been matched by a commensurate improvement in customer outcomes: reliability has been broadly flat to slightly declining in the most recent reporting period,⁴ and, as discussed further in section 4.2 below, the productivity gain built into the framework has in practice been more than offset by real price effects, leaving customers with no visible dividend.

Networks retain considerable discretion over how they respond to the transition – what to invest in, when, and how much risk to take on in the process. Adaptation of some kind is inevitable, but the current framework does not appear to reliably align the choices networks make with the interests of the customers who ultimately fund them.

This report considers four inter-related reasons for that misalignment: the allocation of risk between networks and consumers; the information asymmetry that shapes the propose-respond model; the design of cost and other incentives; and the limitations of the current approach to customer engagement. As discussed further in section 3.1, a consistent feature of the current framework is that it insulates NSPs and their investors from much of the risk created by the transition. That risk does not disappear – it is transferred to consumers, who typically have little practical ability to manage it themselves, and who increasingly experience it as sustained increases in network charges.

Two further, related issues cut across all four themes: network utilisation and productivity. Because NSPs earn a return on their regulatory asset base largely irrespective of how intensively that asset base is used, the framework provides only a limited incentive to make full use of existing network capacity before committing to new investment. While AER's performance reporting shows that distribution network utilisation continued to rise in 2025, to 46 per cent⁵ this is still lower than in the late 2000s when the national regulatory framework was introduced. Moreover, distribution networks will need to accommodate increasing demand from electrification, which will drive a new step change in capacity unless opportunities are taken to manage demand through non-network options. Meanwhile, the Integrated System Plan (ISP) is driving a massive build-out of new transmission that is decoupled from consumer demand for these services, as it is primarily driven by the shifting patterns of bulk generation and storage. Unsurprisingly, both transmission and distribution Total Factor Productivity are declining and both are lower than in 2006 (the start of the AER's data set).⁶

The AER's Future of Network Regulation information paper likewise recognises that NSPs are increasingly functioning as platforms that blur the boundary between monopoly and contestable services, and asks whether the current framework remains fit for purpose as the system evolves⁷ – the same question this report seeks to address.

3 Risk is the key driver of regulatory outcomes

The fundamental driver of the current regulatory framework is the premise that the regulated NSPs are low risk businesses. This manifests in multiple aspects of the framework, as follows:

- Resource-intensive review processes – because the NSPs do not wish to be exposed to the risk of overspending, they require their business plans to be assessed ex ante by the AER, so that they are clear on their revenue allowances. This in turn requires the AER to seek extensive evidence in support of each element of the business plan in order to manage overspending risk on behalf of consumers.

² AER, Network performance report 2026, July 2026, p. 13

³ AER, Network performance report 2026, July 2026, p. 15

⁴ AER, Network performance report 2026, July 2026, p. 35

⁵ AER, Network performance report 2026, July 2026, p. 32

⁶ AER, 2025 Annual Benchmarking Report – Distribution network service providers, November 2025 and AER, 2025 Annual Benchmarking Report – Electricity Transmission Network Service Providers, November 2025

⁷ AER, Future of network regulation – Information paper, June 2026

- Low levels of innovation – innovation is an inherently risky process, and the best party to take these risks is the innovator themselves. Understandably, the AER limits the amount of direct innovation funding available to NSPs
- Limited scope for anticipatory investments – such investments represent a risk-benefit trade-off, i.e. the risk that making a larger investment in anticipation of future needs does not pay off as the need does not eventuate. If NSPs were prepared to bear the risks and retain the benefits of such decisions, there would not need to be such strong oversight over such investments.
- Incentives – while the cost incentives are sometimes described as “strong”, consumers bear around 70 per cent of any cost overrun, and the NSP only 30, as explained further in section 5.1. Consumers also retain 70 per cent of the benefit of cost savings. But in a competitive market, the cost incentive rate is typically 100 per cent, unless a business can pass through some of its cost increases.
- Transmission – policymakers’ decision to not progress any form of Transmission Access Reform, which would have placed more of the risks of Transmission overinvestment onto other parties better able to manage/mitigate that risk (generators; large loads), has left small customers bearing that risk. Cost escalation in transmission will not be mitigated by greater customer numbers – in fact high levels of CER and other local generation/storage make small customers less dependent on the transmission system. Transmission costs are also likely to be higher than under a framework with stronger signals for where to locate new generation, i.e. siting risks also are ultimately borne by customers.

3.1 Risk has increased since the framework was introduced

While the framework has iterated from its original design through various relevant rule changes, the basic framework has been consistent since its introduction in 2008 (and is similar to the state-based frameworks that preceded it).

At that time, the electricity system was relatively predictable. Virtually all power was generated from large generators and transported to users through the transmission and distribution networks, which only had to accommodate one-way flows, which were relatively predictable. Generator investment and disinvestment was generally steady. In some instances it was boosted by policy interventions, but these were typically based on imposing specific targets for new generation of qualifying types (LRET, Queensland Gas Scheme) making it highly predictable. Demand grew fairly steadily in line with economic growth, albeit the increase in air conditioner penetration was driving peak demand faster than consumption. It was rational to err on the side of over forecasting the rate of demand growth, as the downside was simply that any required augmentation occurred a few years earlier than strictly necessary. At the time, some argued that policymakers were missing out on opportunities to encourage demand management as a lower cost alternative to system build.

Many of these factors are no longer the case:

- The rapid rise of consumer energy resources (CER) such as rooftop PV and batteries is driving two-way flows and limiting peak demand growth in many areas of the distribution network. Notably, though, CER is underutilised as an asset to the system despite CER investment being at a comparable level to network investment.
- The risk of augmentation investment becoming a future stranded asset is no longer negligible. Significant greenfield investment in transmission is required for the first time in over a generation. Forecasting the cost and timing of this investment appears to be especially challenging, based on the experience of projects such as Energy Connect, HumeLink and VNI West, as documented further in section 4.4.
- New large loads are also emerging for the first time in decades, primarily at distribution network level, in the form of data centres. The current concerns around the impact of data centres on the electricity system and its other users are also – at least in part – an outworking of the framework’s low risk exposure for networks, including the risk that other network users are effectively the creditor of last resort if a large load defaults on its obligations. While these concerns are often framed around whether the rules are fit for purpose, one reason the rules are as they are is because they protect NSPs from the consequences of connecting large new loads to the grid.

- Electrification may drive significant demand increases, especially in areas where gas is currently widely used for space heating. But the pace of this trend is uncertain and may be impacted by policy changes. For example, the Opposition in Victoria is signalling plans to roll back key elements of the current Government's Gas Substitution Roadmap. The Consultation Paper notes that "change in government policy is challenging to forecast for NSPs and the pace at which policy changes are implemented and the speed at which consumers respond is also difficult to plan for".⁸ In any case, the degree to which distribution network capacity increases result from electrification depends on granular assessments, particularly against the counterbalancing impacts of local solar and storage, and the interaction of these assets with the network.
- While extreme weather has always been a factor to contend with, the frequency and intensity of such events is increasing with climate change.⁹ Extreme weather events drive network costs in two ways. Firstly, networks are exploring the case for investment in resilience – ex ante expenditure to reduce the risk or impact of damage to networks from extreme weather. This is a novel area and it's unclear how best to calibrate current investment against future, uncertain benefits. The framework also focuses on *network* resilience rather than *consumer* resilience which should be the ultimate goal. Secondly, they incur repair and restoration costs after the event. Given their nature, such expenditures are typically recovered ex post through pass-through provisions, which reduces the scope for scrutiny of the costs. Network approaches to these challenges do not take adequate account of consumer preferences and opportunities to leverage off CER for improved resilience outcomes.¹⁰ The ways the framework mitigates extreme weather risks is also documented in Table 2.

Fortunately for NSPs and their investors, the current framework insulates them substantially from the financial impacts of these increased risks (as detailed thoroughly in Section 3.3). However, the risks and their impacts do not disappear. They are instead imposed on consumers, despite consumers having little if any scope to manage these risks themselves. For many consumers, this has manifested as higher network charges over time. The most common mitigation that consumers use is to invest in CER such as rooftop PV and batteries that reduce their reliance on grid electricity and allow them to minimise their exposure to network costs. But these investments to date have done little to reduce network costs, which include significant sunk costs, and so this mitigation in turn imposes even higher costs onto other customers.

3.2 NSP attitudes to risk

NSPs and their investors appear to prefer a low risk framework. This may inhibit efforts to make NSPs take more risks even if greater rewards are on offer. Evidence for these attitudes can be found in investor materials and NSP submissions to rule changes.

Equity investor materials are explicit on this point. In a roadshow presentation to Asian investors, Spark Infrastructure – at the time part-owner of TransGrid, SA Power Networks and Victoria Power Networks – described the regulatory framework as one that "provides revenue certainty and inflation-linked revenue, and gives businesses incentives to outperform".¹¹ Two years earlier, in a similar roadshow presentation, Spark described the ability of NSPs to recover the costs of efficient investment and retain the benefits of outperformance as "a critical underpinning" of the framework, and warned that "changes in regulation will only create uncertainty in the minds of investors, which can only lead to higher costs of capital".¹² AusNet's own investor materials make a similar point about a specific mechanism: its 2020 results presentation credited the fact that "revenues are predominantly set on a revenue cap basis or under long term fixed price contracts" as the reason the business was "well placed to navigate" the uncertainty of the COVID-19 period.¹³

Debt investors and credit rating agencies place similar weight on the framework's risk mitigants. A factsheet on AusNet prepared for retail bond investors lists "minimal exposure to volume risk" under the revenue cap, and the fact that the large majority of AusNet's regulated revenue is "protected from the risk of increases in inflation", as

⁸ Victorian Government, Consultation paper, June 2021, p. 77

⁹ NSW Environment Protection Authority, Climate change trends – extreme weather events, accessed September 2026: <https://www.epa.nsw.gov.au/Your-environment/Climate-change/Trends/Extreme-weather-events>

¹⁰ Erne Energy, Consumer Electricity Resilience, October 2024

¹¹ Spark Infrastructure, Asian Roadshow Investor Presentation, February 2019

¹² Spark Infrastructure, Asia Investor Presentation, November 2017

¹³ AusNet Services, FY2020 Full Year Results Release and Presentation, May 2020

explicit credit strengths.¹⁴ Moody's cited AusNet's "predictable and stable revenue derived from its regulated networks under a mature and transparent regulatory framework" as a driver of its 2022 rating action, alongside the "staggered nature of its regulatory resets providing a buffer to the risk of abrupt decline in regulated revenue at regulatory reset".¹⁵

Networks' risk aversion extends to their approach to rule changes and other regulatory reform. During the Transmission Frameworks Review, Grid Australia "considered it would not be reasonable to expose TNSPs to congestion risk".¹⁶

Taken together, this evidence points to a consistent preference among network investors for lower risk over higher expected returns. This matters for the ENRR: proposals to expose NSPs to materially greater risk – whether through congestion risk, more binding non-network competition, or reduced guaranteed cost recovery – are, on this evidence, more likely to be resisted by networks and their owners than embraced, regardless of the return that might in principle be available to compensate for that risk. While this evidence may be considered anecdotal and indirect, it's important that the AEMC satisfy themselves that networks will respond constructively to greater risk exposure and accountability if they choose that reform route in their final recommendations, noting that the quid pro quo would likely be access to higher returns.

3.3 Risk and the rate of return

Rate of return analysis typically distinguishes between market-wide (systematic) risks to be considered separately from firm or industry specific risks (non-systematic, or idiosyncratic). This is because finance theory posits that investors can diversify away idiosyncratic risk but not systematic risk. Different companies have different exposures to systematic risk and this is termed beta. Listed company betas can be observed through statistical analysis. Idiosyncratic risks need consideration too, but they are not compensated for through the rate of return. In practice it may not be possible to neatly separate risks into these two categories, but it provides an analytical framework for risk. The current regulatory framework provides substantive risk mitigation for NSPs as set out in the following sections.

3.3.1 Systematic risk

There is no definitive list of systematic risks to which markets are exposed. However, ten commonly mentioned systematic risks are considered in **Table 1**. The third column in the table describes whether or how these risks are addressed within the AER's regulatory framework for determining networks' revenue allowances.

Table 1: The regulatory treatment of systematic risks in the AER framework

Systematic risks	Description	Regulatory treatment
1. Interest Rate risk	Higher interest rates will negatively affect the value of investments.	Trailing average allowance for the cost of debt over 10 years. Return on equity updated 5-yearly to account for interest rate movements. Firm free to rebalance their gearing around a benchmark gearing ratio.
2. Inflation risk	Rising prices will erode the real value of future cash flows or returns.	The value of the regulated asset based (RAB) is indexed by outturn inflation in the AER's Roll Forward Model (RFM) and revenues are indexed for outturn inflation in its Post-Tax Revenue Model (PTRM). Estimation period for expected inflation reduced to 5 years (in 2020). The AER has explained, "This allows our forecast inflation rate for new network determinations to be more responsive to changes in market circumstances. This change will likely lead to a lower difference between forecast and actual inflation than would have otherwise been the case." ¹⁷

¹⁴ FIIG Securities, AusNet Services Factsheet, May 2024

¹⁵ Moody's Investors Service, AusNet Transmission Group Pty Ltd – Rating Action, February 2022

¹⁶ AEMC, Transmission Frameworks Review Directions paper, April 2011, p. 38

¹⁷ AER, Electricity network performance report, July 2023, p.42

Systematic risks	Description	Regulatory treatment
3. Equity Market Risk	Broad market declines or volatility due to changes in investor sentiment, economic outlook, or valuation levels.	See response below to liquidity risk.
4. Exchange Rate risk	Affects the value of assets due to fluctuations in currency exchange rates. Companies that import or export goods are particularly exposed.	See response below to input price risk.
5. Input Price risk	Broad-based changes in input prices affecting the entire market.	5-yearly resets providing allowances based on current and projected efficient costs. Cost pass-throughs and re-openers available to address material and unexpected increases to input costs. Regulatory incentive schemes financially reward efficient management of costs.
6. Business Cycle risk	Economic downturns leading to widespread declines in output, employment, and profitability.	Revenue capping shields revenues from shifts in demand. Price capping shields revenues from expected shifts in demand. Fixed connection charges unrelated to usage. Revenues smoothed within a regulatory period (using X-factors). Networks do not bear the risk of unpaid customer bills (i.e. retailers must pay networks regardless of whether customers pay their bills).
7. Political and Regulatory risk	Changes to government policy, regulation, taxation, or political instability affecting the entire market.	Stable political system with thorough processes informing policy and regulatory decision making (e.g. benefit cost analysis, regulatory impact statements, parliamentary review of new regulations, rule change requests, etc). Allowances for nominal post-company tax, and pre-imputation return on equity. Allowances for other taxes (e.g. State taxes).
8. Liquidity risk	Widespread financial instability due to credit market freezes, liquidity shortages, or banking crises.	The regulated rate of return accounts for contemporary and expected financial market conditions.¹⁸ Re-openers available to address material liquidity constraints.
9. Environmental	Broad market impact arising from widespread environmental degradation or natural disasters.	Cost pass-throughs and re-openers available to address material and unexpected costs arising from natural disasters.
10. Technological or Structural risk	Widespread technological disruptions or structural shifts that affect market-wide valuations. ¹⁹	5-yearly resets provide allowances based on available or expected technologies. A 'guaranteed' rate of return is earned on all 'prudent and efficient' investment regardless of the assets' utilisation. Allowances provided for stranded assets (via accelerated depreciation). Since 2022, allowances also provided for <i>potential</i> stranding risk (discussed below).

¹⁸ In its explanatory statement for the 2018 RORI (December 2018), the AER observed, "We consider that although an efficient firm providing regulated energy network services has high financial leverage –relative to the market average – this does not necessarily imply it has an equivalently high overall exposure to financial risk.", December 2018, p. 49.

¹⁹ CRG, Submission to AER Rate of Return Instrument – Review discussion paper, December 2025: The CRG considered most (if not all) **systematic risks associated with the energy transition** are already captured within the other categories identified in Table 3. Of course, the energy transition may also create idiosyncratic risks for

3.3.2 Idiosyncratic risk

Similarly, there are no standard lists of idiosyncratic risks, however, the discussion in section 3.1 can serve as a guide to some of the risks specific to the sector.

Table 2: The regulatory treatment of idiosyncratic risks

Idiosyncratic risk	Description	Regulatory treatment
Demand risk	The risk that customer demand for traditional network services falls, for example due to CER take-up.	Revenue cap.
Regulatory risk	Changes in the regulatory framework that increase cost or otherwise disadvantage the regulated business.	NSP can seek a re-opener specifically for regulatory event. Step changes allowed in opex building block. Some regulatory risk is endogenous to the regulator and thus hard for the framework itself to mitigate.
Technology risk (industry-specific)	New technologies disrupt the business or impact its operations (e.g. renewables, batteries).	Revenue cap (where demand is affected). No exposure to congestion/curtailment costs as new generation types connect. Compensatory investments (System strength and inertia requirements, emergency backstop etc) generally fully funded via contingent projects or reset allowances.
Input price risk (industry specific)	The risk that costs rise faster than expected.	Real price impacts are included in the opex building block. The CESS and EBSS limit the exposure to excess costs to 20-30%.
Stranding risk (idiosyncratic component)	The risk that a network's assets become redundant ahead of their economic life for reasons specific to that network	Accelerated depreciation and any potential-stranding allowance (see Table 1, row 10) are assessed and applied on a network-specific basis. The regulatory requirement is to provide a "reasonable opportunity" to recover efficient costs. This includes sunk costs.
Construction/delivery risk	The risk that a specific project's capex and delivery timeframe exceed those assumed in its original cost-benefit case, for reasons specific to that project (e.g. supply chains, contractor performance, community and planning approvals).	The contingent project mechanism allows for a project-specific ex post cost assessment (see section 4.4 below). In practice, cost increases have been substantially passed through to consumers via the RAB, with limited consequences for the NSP beyond reputational effects and, where relevant, incentive scheme outcomes.
Extreme weather damage and liabilities	The risk that a network's assets are damaged or destroyed by extreme weather. The risk that a network faces liability if its assets are considered to have caused a bushfire.	Unlike in the US where bushfire liabilities have bankrupted some utilities, Australian utilities are substantially protected. Ex ante they can claim costs for jurisdictional risk mitigation requirements (REFL program in Victoria) Ex ante they may be able to claim costs for network hardening Ex ante they can claim efficient insurance costs.

energy networks, but these are diversifiable and therefore do not require compensation through the regulated cost of capital.

		Ex post there are pass through provisions for extreme weather events, insurance coverage and insurance credit risk.
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Hypothetically TNSPs and DNSPs might face different levels of systematic risk and so might merit different beta estimates in their rate of return. However, the AER does not really have data or other tools to test this hypothesis, as explained further in Appendix B. This Appendix also canvases whether other elements of the rate of return should be capable of variation between Transmission and Distribution, or even between individual networks. This would require changes to the NEL, but there could be merit in addressing rigidities in the current requirement to set a single binding rate of return every four years. Accordingly, the ENRR represents an opportunity to consider the pros and cons of the single binding rate of return against one that varied by network type and against a return to setting a rate of return for individual networks within their own reset process. Safeguards would need to be considered against an inefficient use of resources by the AER, NSPs and other stakeholders in re-prosecuting the same issues every year.

Finally, the current rate of return framework is unlikely to be amenable to menu-style regulation such as the PREMO approach in Victorian water,²⁰ to the extent such an approach is considered an appropriate outcome of the ENRR.

3.4 Risk aversion and a preference for control

A key consequence of NSPs' low risk appetite is an apparent preference for control and ownership of assets. To date this has manifested in ways such as:

- Low incidence of non-network options in RIT-T/RIT-Ds.²¹
- Limited use of price signals to elicit demand response and allow customers with CER to value-stack. This has been explored in the AEMC's Pricing Review.
- Such demand response that does exist has largely been reliant on network-controlled assets such as controlled load hot water.
- Applications for ring fencing waivers to allow NSPs to directly own and control DER assets such as network-side batteries, EV charging infrastructure.

As a result, there are low levels of active CER integration (as in, active management and co-ordination of batteries and other flexible devices) in Australian networks and low levels of dynamic response. This is despite:

- High levels of penetration of CER in Australian electricity systems - over 36% of rooftop solar-suitable dwellings have rooftop PV.²²
- The clear importance of co-ordination of assets in future system plans - the 2026 ISP envisages half of the 35GW of distributed batteries to be co-ordinated.²³
- The fact that investment in CER is comparable investment in networks – Household investment in rooftop PV is running at around \$5bn pa, battery expenditure is in the order of \$2bn pa, while combined network capex in 2025 was \$8.5bn.²⁴
- Evidence from other jurisdictions that active CER integration is entirely feasible. Great Britain has developed the world's largest local flexibility market, moving from virtually no formal procurement by electricity networks in 2019 to 31GW tendered and about 9GW contracted volumes in 2025.²⁵ New York has developed a Value of

²⁰ Essential services commissions of Victoria, Water Pricing Framework And Approach - Implementing PREMO from 2018, October 2016

²¹ See for example analysis by Energeia in Renew DER Optimisation (Stage II): Final Report, September 2021

²² AEMO, 2026 Integrated System Plan for the National Electricity Market, June 2026, p. 40

²³ Ibid, p. 106

²⁴ AER, 2026 Network Performance Report, July 2026, p. 20

²⁵ Ferguson, A., Blake Clough Consulting, DSO Flexibility Markets Transforming GB's Grid Economics, October 2025: <https://www.blakeclough.com/dso-flexibility-markets-transforming-gbs-grid-economics/>

Distributed Energy Resources (VDER) compensation mechanism,²⁶ which includes two network elements, the Locational System Relief Value (LSRV) and the Demand Reduction Value (DRV).

3.5 Risk and innovation

The low risk framework means that networks are simply not well placed for genuine innovation. Networks can and do implement new technologies and techniques as part of their business as usual cost management. But this activity does not require any special incentives and allowances as it is deployment rather than research and development (R&D). R&D is a risky, iterative process and so is poorly suited to a risk-averse culture and regulatory constraints on maximising the returns from successful innovations.

Infrastructure companies can and do carry out innovation, but the context is important. Bell Labs is one of the most famous innovation engines of any organisation and this came out of the American monopoly telephone service AT&T. But this was in the context of a very large monopoly with a rapidly growing market and very loose regulation. This means that Bell Labs was extremely well resourced and able to pursue multiple research and development projects. They tended to prioritise technological improvements for cost reduction and/or improved physical delivery of telephony services. While this benefited customers somewhat the main direct beneficiaries were shareholders who enjoyed lower costs with limited pressure to reduce prices. Spillover benefits occurred much later as specific innovation such as transistors and solar PV panels were further developed by other parties and eventually found widespread use. In this respect Bell Labs was like a privately owned CSIRO.

But *customer-oriented* innovation only really took off once AT&T was broken up and its successor companies were competing against each other. It was really only after 1984 that a genuine consumer market in phones, answering machines, and "designer handsets" took off. Custom Local Area Signalling Services (CLASS): Caller ID, Call Waiting, Three-Way Calling, Call Forwarding became commonplace and toll-free easy to remember 1-800 numbers became prevalent as a business marketing tool as their price came down significantly. All these innovations *existed* prior to the break up, but were not prioritised or priced competitively by the monopoly.

In energy, a standout example is National Grid Ventures - the venture capital arm of National Grid. Crucially this is held outside of its various US and UK regulated network businesses²⁷ and National Grid is much larger in scale than individual Australian network businesses so can deploy more capital.

Accordingly, unless NSPs choose to expose themselves to the real risk of failure, for example by carrying out R&D activities outside their regulated business, they will be poorly placed to drive real innovation. Improvements in consumer service and outcomes from innovation will need to come from the competitive sector and major public research centres, and the key issue will be ensuring timely *deployment* of successful innovations where relevant.

The DMIS outcomes serve as an example where this is not happening, as discussed further in section 5.2.1. A few networks have utilised this incentive to deliver generic solutions such as back-up generation, demand management incentives and direct load control. These limited examples have significant net benefits with large cost: benefit ratios. So it's implausible that wider deployment would not still have net benefits but this is not occurring. Accordingly the diffusion of even slightly novel approaches is not happening despite the incentives being in place.

Accordingly, the type of "innovation" we can expect of networks is not driven by innovation allowances. Potentially it could be incentivised by well structured, balanced cost incentives and greater use of benchmarking or once proof of concept has been achieved greater deployment could be made mandatory through the merit order approach

3.6 Implications for future approaches to network regulation

There are two potential ways forward in the light of the above analysis.

²⁶ Ascend Analytics, VDER: New York's Unique Community Solar Program, August 2025: <https://www.ascendanalytics.com/blog/new-york-vder-program-value-of-distributed-energy-resources>

²⁷ <https://www.nationalgrid.com/national-grid-ventures>

1. Increase genuine accountability & risk exposure, noting that this would have implications for overall returns required, or
2. Impose more directive requirements on NSPs to deliver desired outcomes, whether via the NER or via an empowered AER

The two options are not mutually exclusive. Some elements of the framework may better suit greater accountability, while others may suit greater direction. In addition, in either case, the framework should be bolstered by stronger, symmetric incentives with challenging baselines as discussed in section 5.

3.6.1 Increased accountability

At a high level, this entails providing clear goals for NSPs to deliver system benefits such as continuing reliability and resilience, reduced congestion or greater levels of CER co-ordination but leaving it up to them to find the lowest cost solutions. The ability to pass on higher levels of costs to achieve these goals would need to be restricted. At one end of the spectrum this could entail treating demand more as endogenous rather than exogenous, and relying on NSPs to find ways to shape demand to maintain reliability rather than simply building more infrastructure to meet projected demand. Of course, as underlying “native” demand increases, some augmentation is still likely to be required, and this possibility would have to be factored in.

The challenge to develop a regulatory framework that preserves accountability is how to specify the desired outcomes and to calibrate ex ante allowed revenues without getting into a detailed review of a business plan.

Another dimension of accountability is to introduce some form of menu regulation, which forces NSPs to choose their level of ambition. In Victorian water regulation, the PREMO model does this by requiring water businesses in consultation with customers, to decide on the services to be delivered, the prices to be paid and the level of risk each business assumes on behalf of its customers. Each business also self-assesses the level of ambition of its pricing proposals, which influences the allowed return on equity.²⁸

3.6.2 Increased direction on NSPs

If NSPs appear unwilling to take on more risk, even if greater returns are potentially available, then the alternative method to drive the transition is direction, whether through more prescriptive rules, or through empowerment of the AER to direct NSPs to achieve specific goals or targets. AER direction could entail through absolute requirements, or incentives designed to encourage the desired outcomes, or a mix of the two. NSP costs would still be an input into regulatory decision making, but the onus would be more in the regulator to determine the overall direction of the business plan.

This could extend to designing decision-making tools to drive goals such as greater utilisation, and greater uptake of services from CER. One such approach is to design a network capacity “merit order” that seeks to reverse the traditional capex first approach by requiring NSPs (particularly at the distribution level) to test non-network alternatives first and reserve augmentation for a last resort. At a high level the merit order could be structured as follows:

1. Tariff design
2. Network support payments to existing CER/DER/other service providers as relevant
3. Flexible connection agreements
4. Tender for services from new non-network service providers
5. Brownfield investment (where a relevant option) – increasing the capacity of existing infrastructure
6. Greenfield investment – building new infrastructure.

The merit order set out above would require the AEMC or AER to specify not just a principle but a sequence networks must follow. While such action would seem out of character for Australian regulators, there is significant

²⁸ Essential services commissions of Victoria, Water Pricing Framework And Approach - Implementing PREMO from 2018, October 2016, p. 14

overseas precedent for regulators taking exactly this approach with consumer-owned batteries, EV chargers and flexible appliances specifically. Germany's Bundesnetzagentur requires distribution network operators to enable curtailment of household batteries, EV chargers and heat pumps above 4.2kW during genuine network congestion, in exchange for a mandated minimum supply guarantee and a fixed tariff discount set by the regulator rather than negotiated network by network.²⁹ Several US state commissions have gone further still, directing utilities to install specific volumes of grid-scale storage and to stand up virtual power plant programs that pay customers for the flexibility of their batteries and EV chargers, rather than leaving take-up to each utility's own commercial judgement.³⁰ California's interconnection rules achieve a similar result by mandating that every battery and EV charger connecting to the grid carry the same enforceable curtailment and control functionality, applied uniformly rather than left to case-by-case network discretion.³¹

In each case, the regulator specifies the outcome required of the network and the consumer benefit follows from that specificity: a predictable, system-wide contribution from CER to managing network costs on a known timetable, rather than whatever subset of networks finds it commercially convenient to pursue. This is the same logic underlying the merit order proposed above, and the experience of these jurisdictions suggests that a more directive Australian framework need not be a leap into the unknown.

4 Asymmetry

The AER operates an incentive based regulatory (IBR) framework. Under IBR, the regulator sets an ex-ante maximum revenue allowance for each business it is regulating, usually expressed as an annual amount for each year of a multi-year period (typically five years). This creates an incentive for the business to spend less than the allowance, which enables it to make extra profits. The value to the customers of the business is that by incurring lower expenditure it is revealing information to the regulator that allows it to set lower allowances in the next regulatory period. A key premise of network regulation is asymmetry of information – that the network knows better than the regulator what its efficient costs look like (and even the network is operating under uncertainty). So it is not an option for the regulator to simply be better at setting revenue allowances. It has to rely in part on incentivising the network to be efficient and in so doing reveal its efficient costs.

There are two broad approaches: CPI-X and building blocks. CPI-X is the original IBR approach. It acknowledges that the NSP faces underlying upward cost pressures due to inflation but that (as is demanded of competitive firms in an economy) inflation is offset by productivity gains (the "X" factor in CPI-X). The advantages of this approach include its simplicity and the fact that it continues to drive the costs of the regulated business down, across multiple price control periods (providing the regulator is able to maintain a positive X-value). Critically, it does not require the regulator to attempt to overcome the significant information asymmetry between it and the regulated business because it does not require the regulator to evaluate a detailed business plan.

The drawback of CPI-X arises when there is a chance that the efficient bundle of costs is higher than in the previous period. It would take a brave regulator to allow a CPI+X price path without scrutinising the underlying business plan. The alternative, which is used by the AER (and many other regulators), is a building block approach. This entails using detailed forecasts of expenditure, of financing costs, depreciation rates and tax payments. These building blocks are then combined to determine allowed revenue. The AER's approach is also a propose-respond model. The businesses develop business plans, which the regulator will then scrutinise, challenge and potentially adjust the business plans where it is not convinced that expenditure is justified. This element of the process is typically called propose-respond. Both the building blocks and propose-respond are embedded in the rules.

The building block approach is much more resource-intensive than CPI-X and requires that the regulator is confident it can substantially address the information asymmetry in its evaluation of business plans. Its

²⁹ Bundesnetzagentur, [Bundesnetzagentur sets rules for the integration of controllable consumer devices](#) [press release], 27 November 2023.

³⁰ Utility Dive, Illinois sets 3-GW energy storage target, requires utilities to develop virtual power plants, 8 January 2026.

³¹ California Public Utilities Commission, Electric Rule 21 – Generating Facility Interconnections, accessed September 2026: <https://www.cpuc.ca.gov/rule21/>

advantage over CPI-X is that is more flexible in responding to industry developments that might lead to a step change in costs.

A propose-respond model also favours the NSP due to several factors well-founded in behavioural economics.

Anchoring-and-adjustment. final judgments are insufficiently adjusted away from an initial value. This can be the case even when that value is transparently arbitrary or irrelevant.³² Even experienced professionals in a field can be affected by this phenomenon, and may be unaware of its impact.³³

First-mover advantage in negotiation framing. The anchoring effect arises because propose-respond is structurally a negotiation with the network moving first. First-mover advantage is real, but can be mitigated by actively interrogating the rationale behind the first offer or anchors on their own target value instead.³⁴ This is likely to be consistent with techniques that the AER uses in evaluating network proposals, and it's critical under a propose-respond model that the regulator has the right to do so. Benchmarking is a useful example of a regulatory tool that is not anchored in an NSP proposal

Bounded rationality. The AER does not have unlimited resources or time (nor do the networks). Under such resource constraints decision-makers "satisfice" rather than optimise.³⁵ In practice this means that the AER has to prioritise which elements of the proposal to focus its time and resources on, meaning other elements are more likely to benefit from anchoring.

Status quo bias / loss aversion reinforces the implications of bounded rationality. Decision-makers disproportionately favour the status quo alternative across many contexts, including consequential real-world choices, partly through loss aversion around departing from a default.³⁶ Making a change to an existing parameter or approach can be psychologically coded as the risky, effortful, criticisable move.

This latter also potentially impacts regulatory decision making by the AER where it has processes in place, such as benchmarking, productivity adjustments and incentive strengths, which have a higher degree of stability than would appear warranted.

Notwithstanding the AER's valiant attempts to overcome the advantages to the networks of their greater information and the propose respond model, the framework remains highly asymmetrical in favour of networks in several respects. Asymmetry in incentives are discussed further in the next section, while below asymmetry in cost estimation is reviewed, with a focus on the opex building block.

4.1 Benchmarking

The AER uses benchmarking to *inform* its cost assessments, both in terms of overall opex and for capex unit costs. However, it doesn't use benchmarking in place of NSPs' own costs. The specific techniques are not considered here in detail, suffice to say that the AER uses a range of statistical tools to benchmark NSP costs, adjusting for a set of standard cost drivers. The benchmarking process has been consulted on and so NSPs have

³² See e.g. Tversky, A., & Kahneman, D. (1974). Judgment under Uncertainty: Heuristics and Biases. *Science*, 185(4157), 1124–1131.

³³ See e.g. Northcraft, G. B., & Neale, M. A. (1987). Experts, Amateurs, and Real Estate: An Anchoring-and-Adjustment Perspective on Property Pricing Decisions. *Organizational Behavior and Human Decision Processes*, 39(1), 84–97.

³⁴ See e.g. Galinsky, A. D., & Mussweiler, T. (2001). First Offers as Anchors: The Role of Perspective-Taking and Negotiator Focus. *Journal of Personality and Social Psychology*, 81(4), 657–669.

³⁵ See e.g. Simon, H. A. (1955). A Behavioral Model of Rational Choice. *Quarterly Journal of Economics*, 69(1), 99–118.

³⁶ See e.g. Samuelson, W., & Zeckhauser, R. (1988). Status Quo Bias in Decision Making. *Journal of Risk and Uncertainty*, 1(1), 7–59.

had ample opportunity to challenge the AER on its process. Few if any other stakeholders have the resources or information to participate. Cost categories that may distort the benchmarking are separated out and forecast separately as category specific forecasts, with the remaining opex that is subject to benchmarking termed base opex.

NSPs may also propose (although the AER need not accept) adjustments for Operating Environment Factors (OEFs) to reflect factors that make their business more costly to run. In some cases this may be a factor that is common to all networks but may impact some networks more than others. For example, AusNet has proposed an OEF to reflect their position that the terrain of their network area is more challenging than other networks, making it costlier to serve. Whether or not this is true, the corollary of this claim is that another network has an easier terrain than the typical or average network. Given benchmarking is a relative comparison, the network with easier-than-average terrain should arguably have a negative OEF applied. But that network is not going to advertise the fact and may not even test for it, and other stakeholders are unlikely to have the information or resources to make the case.

The AER also does not use the benchmarking results in a determinative sense. Instead it takes the position that if an NSP's base opex is no more than 25 per cent above the efficiency frontier indicated by the benchmarking result, then it is "not materially inefficient" and no efficiency adjustment is made, i.e. the NSP's own actual base opex is used as a starting point. As a rough point of reference for the materiality of this, the average opex allowance across the 14 DNSPs in their most recent round of determinations was \$1.479bn³⁷ and 25 per cent of that is \$370m, or \$74m annually. Note that the efficiency frontier is just the relatively most efficient DNSP, the actual achievable efficiency frontier may be even lower cost. NSPs get further leeway by being able to propose their preferred base year, although the AER may disagree. In their last reset, Ergon and Energex's preferred base year was deemed materially inefficient, but the AER substituted in a different base year. On the one hand this was a lower cost starting point, but on the other, there was no adjustment for inefficiency.

4.2 Trend, step, change

The opex forecast is then constructed by rolling forward the base year opex and adjusting for trend, real price effects and a productivity estimate. The trend adjustment is logical as it uses the same cost drivers as used in constructing the benchmarking. Real price effects are based on the premise that the prices of the specific bundle of costs that an NSP incurs may rise at a different rate to CPI, which revenues are escalated by annually in any case. In principle, prices could rise at a lower rate than CPI and the real price effect would be negative, but in practice, it is always positive. While modest, at an average rate of 0.6 per cent per annum, this still means an allowance of 3 per cent above inflation over five years.

The AER applies a standard modest 0.5 per cent per annum productivity gain, with only one departure in the last round of DNSP resets – TasNetworks proposed and the AER accepted a 1 per cent per annum gain. In other words, the productivity gain is wiped out by the real price effects, so customers see no net benefit.

Networks can then propose a range of step changes. These are intended to represent material, unavoidable increases in costs or new types of costs. On average, DNSPs proposed five new step changes in the last round of resets, averaging \$67m per DNSP, the vast majority of which were accepted. However in some cases the AER adjusted the amount of the step change so the final decision was an average of \$52m per DNSP.

Again, in principle, a step change could be negative. In practice very few negative step changes are proposed – only eight across the 14 DNSPs and they were typically low in quantum. Several of them arose from opex/capex trade-offs, such as fleet electrification (high capex, lower running costs) or specific reliability improvements leading to lower emergency response costs.

Of course, it is plausible that there are more instances of cost increase than decrease, for example on the premise that regulatory burdens tend to increase rather than decrease. But it is not a given that there should be a need for more upward than downward step changes. Inevitably, NSPs will be more assiduous in identifying and quantifying likely increases in costs rather than decreases during the development of their proposal.

³⁷ Note on \$ figures in this section – all are \$2025-6 unless otherwise stated.

In summary, NSPs invariably get to start with their own historical costs and then get a net upward boost in their opex allowances through multiple elements of the framework. Downward adjustments are modest and typically overwhelmed by upward adjustments, eroding any productivity gains.

4.3 Pass-throughs and re-openers

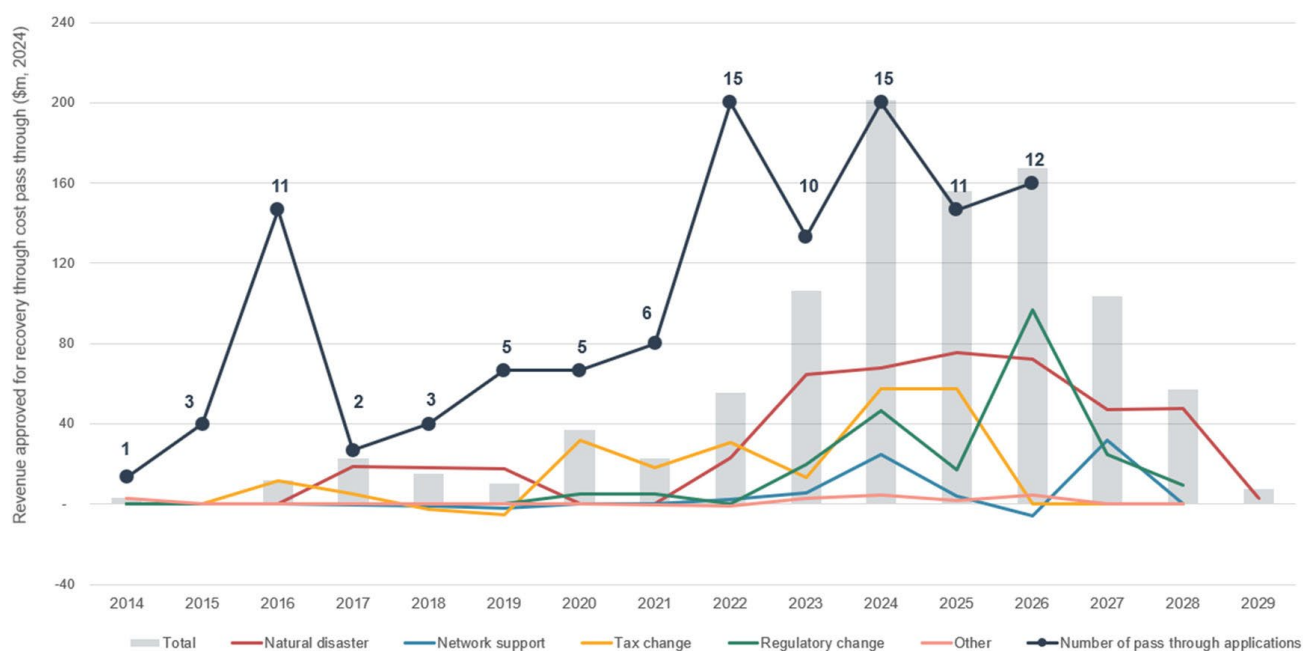
The inherent uncertainty of forecasting is further recognised in the framework by two further risk mitigation tools: pass-throughs and re-openers.

Pass-throughs are applied to cost categories deemed especially hard to forecast, and over which the NSP has little to no influence. The rules allow for four pre-existing pass through categories:

- a regulatory change event
- a service standard event
- a tax change event
- a retailer insolvency event.

In addition to these, DNSPs may propose further categories – natural disasters being the most common, but in the latest round, pass-throughs have been sought for fault level events, electrification, network support, AEMO participant fees, potential long service leave liability and regulatory reform costs. The AER has noted that “cost pass throughs are more frequently positive (increasing allowed revenue) and less frequently negative (decreasing allowed revenue)”.³⁸ In 2025, NSPs recovered an additional \$156m from pass through revenues – approximately 1.1% of the total electricity network revenues, as illustrated in the chart below:

Figure 1: Revenue from cost pass throughs - NSPs - \$ real 2025



Source: AER, 2026 Network Performance report

4.4 Contingent projects

Contingent projects are a specific capex category set out in the National Electricity Rules that allow an NSP to seek an additional capex allowance, outside the normal five-year reset process, for a project that meets defined trigger events and thresholds specified at the time of the reset. They exist because some large, discrete

³⁸ AER, 2026 Network performance report, July 2026, p. 15

investments – particularly in transmission – are not sufficiently certain, or sufficiently advanced in their scoping, to be included as a firm capex forecast at the time of a determination. Rather than force NSPs to either omit these projects entirely or forecast them (and their eventual trigger) years in advance, the mechanism allows the NSP to bring a project forward for a dedicated, project-specific assessment once the relevant trigger event occurs.

In transmission, contingent project capex can be very large relative to the capex otherwise forecast at reset. In 2025, TNSPs collectively invested \$2.9 billion, with over \$2 billion of that directed to ISP-related projects, several of which are being delivered as contingent projects (including early works on ElectraNet's Northern Transmission Project and TasNetworks' North West Transmission Developments).³⁹ It is entirely possible for a TNSP's contingent project capex over a regulatory period to exceed the capex proposed and approved as part of its five-year reset – a dynamic that shifts an increasing share of a TNSP's overall investment programme outside the framework's normal ex ante scrutiny and into the separate, project-specific contingent project assessment.

Before a contingent project (or indeed most other major network investment) proceeds, it is generally subject to a Regulatory Investment Test – the RIT-T for transmission and the RIT-D for distribution. The RIT is a cost-benefit test: the NSP identifies credible options to address an identified need (both network and non-network), quantifies the market benefits and costs of each option under a range of scenarios, and is required to select – and then seek regulatory approval to proceed with – the option with the highest net benefit. The AER maintains application guidelines that set out how the test should be applied, including, since a 2024 update, requirements to consider community engagement and to include changes in greenhouse gas emissions as a market benefit class.⁴⁰

A recurring concern with this process, discussed further in section 3.5 above, is that the NSP proposing the project is also the party assessing the options, including the choice between its own capex-based solution and a non-network (third party) alternative. Even where the process is followed in good faith, the NSP inevitably has better information about its own likely costs and delivery risk than about a prospective non-network provider's, and there is an obvious asymmetry in how carefully each type of option tends to be scoped and costed. This comparability problem is a significant contributor to the low observed incidence of non-network solutions being selected through RIT-T/RIT-D processes to date. Analysis by Energeia in 2021 indicated that less than 10 per cent of RIT-D projects in the preceding 3 years implemented a non-network alternative.⁴¹ Energeia goes even further, stating that the “existing incentive schemes are doomed to fail”⁴² because investors pay a premium for network assets calibrated to their RAB. This means that capital expenditure increases expected shareholder returns by up to \$1.50 for every \$1 of investment, so that the financial incentive for capex dwarfs the alternatives, such as the DMIS or the CESS, which seek to reward avoided capex. This creates a major imbalance, and a huge missed opportunity: non-network alternative accounted for 0.1% of total network spending, despite evidence suggesting that up to 25% of all network expenditure could be replaced with non-network investments, thus reducing costs by up to \$27 billion over the next 30 years⁴³.

NSPs have also pointed to a lack of certainty over opex recovery as a barrier to selecting non-network options, which typically substitute an ongoing, opex-like payment (to the non-network provider) for capex. Because a non-network payment has not previously formed part of the NSP's cost base, NSPs argue there is no guarantee the AER will treat the resulting cost as an efficient part of the opex allowance in the next reset, whereas capex additions to the RAB proceed via a more established process. This concern should, however, be treated with some caution. Because the AER's assessment of efficient opex is itself substantially anchored to an NSP's own historical (base year) opex, a genuine, prudently-incurred non-network payment that is included in actual opex in one period is likely, in practice, to be rolled forward into the base year – and hence into future allowances – in the same way as any other opex cost. On this basis, the opex recovery barrier as characterised by NSPs may be overstated, at least for an NSP that has actually incurred and reported the cost.

The concern about comparability is reinforced by the record of major transmission projects that have proceeded as network solutions. Major transmission projects such as Project EnergyConnect and HumeLink have been

³⁹ AER, Network performance report 2026, July 2026, p. 20.

⁴⁰ AER, Regulatory Investment Test for Transmission application guidelines, November 2024; AER, Regulatory Investment Test for Distribution application guidelines, November 2024.

⁴¹ Energeia, Renew DER Optimisation (Stage II): Final Report, September 2021

⁴² Energeia, 2022 – [Are electricity network incentive schemes rewarding the wrong behaviour?](#)

⁴³ Ibid

subject to substantial delays and cost increases relative to the estimates used in their original cost-benefit assessments. The AER approved a total cost for Project EnergyConnect of \$2.28 billion in 2021;⁴⁴ TransGrid has since revised its own cost estimate for the NSW section of the project to around \$3.6 billion.⁴⁵ HumeLink's estimated cost rose from \$3.27 billion in 2021 to \$4.88 billion in 2024,⁴⁶ even after the AER's 2024 assessment of the project's second contingent project stage reduced TransGrid's own proposed capex for that stage by around \$315 million.⁴⁷ Importantly, these projects' original cost-benefit cases – and hence their apparent net market benefit – were built on materially lower cost estimates.

4.5 Forecasting incentives

Under the AER's propose-respond building block approach where an NSP's forecast is a key input into the determination of the allowance, the regulator must consider ways to elicit accurate forecasts

The underlying incentive is for the NSP to over-forecast, resulting in higher revenue allowances and easier cost incentive targets. This is not to make any specific allegations against Australian NSPs, but it's important to retain the logic of incentives in evaluating an IBR framework. However well-calibrated the incentives are, if the baseline expenditure is set too high, then incentive payments will be poor value for customers' money.

The AER considers it has made progress over recent years to reduce the information asymmetry that can result in inaccurate forecasts and excess allowances, noting in its review of incentives that asymmetry "inevitably reduces over time as we progressively better understand how each NSP operates in practice".⁴⁸ If the AER has indeed reduced the information asymmetry, then that is welcome, but it is unlikely to have fully eliminated it. Indeed, the AER admits as much: "Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between us, consumers and the NSPs remains. Therefore, the risk of over forecasting capex requirements remains higher than under forecasting".⁴⁹

As discussed in section 3.1 above, the sector is facing unprecedented uncertainty. To that end, it has become harder for any party, including the NSP, to "know" what the efficient level of expenditure is. This means a heightened risk that consumers pay more than is necessary for network services. In one sense this makes the AER's task impossible, in another sense it makes it all the more important to structure the incentive properties of the framework in the best way possible to elicit a response from NSPs that uncovers the efficient level of costs over time.

A tool that has been used in the UK and elsewhere to drive accurate capex forecasts is menu regulation. Under menu regulation a set of choices for the regulated business is designed in such a way to elicit accurate forecasts because the regulated business will obtain the best outcome for itself if it chooses consistent with its own best forecast.

This can be illustrated through a type of menu regulation used by Ofgem over multiple price resets called the Information Quality incentive (IQI). The IQI was aimed at eliciting accurate capex forecasts. Ofgem scrutinised the NSPs' initial business plan and in a similar manner to the AER responded with a set of downward adjustments. Having obtained a "baseline" forecast, Ofgem invited the NSPs to submit a revised business plan. The ratio of the revised business plan to the Ofgem baseline then dictated which column of the IQI an NSP would end up with. This determined the allowed expenditure (expressed as a ratio to the baseline), an efficiency incentive rate (the proportion of overspend/underspend that the business would retain) and an additional income figure (which for higher ratios was a negative figure). These parameters were calibrated so that the maximum reward an NSP could obtain would be when its outturn capex matched its forecast. That is, if it deliberately submitted a higher cost business plan, the lower efficiency rate and additional income parameters would leave it with less income ex post, even though it would have a slightly higher ex ante income.

⁴⁴ AER, AER approves costs for Project EnergyConnect [news release], May 2021.

⁴⁵ TransGrid, EnergyConnect update, January 2025.

⁴⁶ TransGrid, HumeLink – Material Change in Circumstance Assessment, March 2024.

⁴⁷ AER, Determination – TransGrid HumeLink Stage 2 Contingent Project, August 2024, p. 10.

⁴⁸ AER, Draft decision - Review of incentive schemes, December 2022, p. 22

⁴⁹ AER, Draft decision - Review of incentive schemes, December 2022, p. 28

Figure 2: Information Quality incentive example matrix

1. Business plan:baseline	100	105	110	115	120	125	130	135	140
2. Efficiency incentive rate (%)	40	38	35	33	30	28	25	23	20
3. Allowed expenditure:baseline	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
4. Additional income:baseline	2.5	2.1	1.6	1.1	0.6	0.1	0.8	1.6	2.4
Total reward:baseline									
Actual expenditure:baseline									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

Source: Oxera, *Assessing approaches to expenditure and incentives*, 2007

The arithmetic properties of the IQI are not in doubt. The main objections to it are likely to be as follows:

1) It has been frequently described as complex, including by Ofgem itself. However, the operation of the incentive can be illustrated by the matrix table above, which indicates it is not that complex. The most complex component is the determination of the baseline, but this has to take place under building block regulation anyway. In fact it avoids the complexity of a second evaluation of the revised business plan because the matrix does all the work.

2) It ostensibly awards the NSP a higher allowance than the regulator's assessment of efficient costs (which for the AER would be in conflict with the rules). In practice, Ofgem knew that its first assessment was relatively aggressive and it typically moved closer to the NSP's forecast in its final assessment because the NSPs had more time to develop their arguments objecting to Ofgem's forecast. So the apparent generosity of the mechanism is somewhat illusory. In any case it may be possible to design the parameters to be less "generous" while still retaining the incentive properties of the matrix to elicit accurate forecasts.

An alternative inducement to forecast accurately is to fast-track initial business plans that are capable of acceptance, i.e. the early signal pathway.⁵⁰ A key factor in this approach is usually that the NSP can show that it has tested its business plan with consumers and obtained their approval. Fast-tracking does not necessarily avoid all regulatory scrutiny, but could significantly reduce it, saving all parties resources and giving NSPs a reason to seek it.

4.6 Expenditure outcomes

Taken as a whole, the framework has produced a long run of material outperformance by NSPs against their allowances, particularly on capex, with underspends the norm for most of the period the AER has been reporting on network performance. Aggregate expenditure has moved to overspend more recently: in 2025, NSPs' actual expenditure exceeded aggregate forecast expenditure by 8 per cent, the second consecutive year of aggregate

⁵⁰ AER, *Better resets handbook*, December 2021, p. 9

overspend, with DNSPs collectively 21 per cent over their allowance and TNSPs 20 per cent under theirs.⁵¹ This recent shift is concentrated in a small number of businesses – Ergon Energy and Energex together accounted for the majority of the 2025 capex and opex overspends, as they did in 2024 – and on the public record to date there is not yet strong evidence that this represents a durable, sector-wide change in NSP spending behaviour rather than business-specific circumstances.⁵²

The distributional consequences of the earlier, longer period of underspend have not obviously favoured consumers. NSPs retained the financial benefit of underspending, through incentive schemes and the treatment of underspend in the RAB roll-forward and base-year opex, while the framework's own productivity assumption – a standard 0.5 per cent per annum allowance discussed in section 4.2 above – has been more than offset by real price effects over the same period, so that customers have not seen a corresponding, durable reduction in network prices. Meanwhile, productivity outcomes remain mediocre. Both Distribution and Transmission are experiencing falling productivity, both in absolute terms and compared to the Australian economy.⁵³

4.7 Implications for future approaches to network regulation

Two priorities stand out from the analysis above. First, given the risk that a tighter cost incentive on its own could encourage NSPs to protect margins at the expense of service quality, the AER should place more emphasis on defining and monitoring the key outcomes it expects from NSPs, so that any erosion in service quality under cost pressure is identified and addressed directly, rather than relied upon to show up eventually in benchmarking data.

Second, some form of menu regulation is worth pursuing to improve the accuracy of NSP forecasts, recognising that most variants would require a rule change to implement. A PREMO-style menu, requiring NSPs to choose their own level of ambition in consultation with customers, could be effective provided NSPs are genuinely prepared to accept the accountability that comes with that choice; alternatively, an IQI-style approach could reduce the incentive to over-forecast, though the AER would need the flexibility to iterate the parameters in response to how NSPs actually respond once the mechanism is in place.

Tightening benchmarking to drive greater efficiencies remains a useful option: it would sharpen the AER's existing tools without requiring a rule change, but on its own it does not address the more fundamental forecasting and outcome-monitoring issues identified above.

5 Incentives

5.1 Cost incentives

In evaluating incentive schemes, it's important to consider how the regulatory settlement would operate in their absence. The AER's approach is a variant of incentive-based regulation, where an ex ante revenue allowance is set for a regulatory reset period (typically five years) and the NSP is incentivised to find cost savings. Absent specific incentive schemes, the savings are retained to the end of the reset period and then the AER adjusts the Regulatory Asset Base (RAB) in the case of capex, or factors the observed opex savings into its base year analysis for the next period. In this way, customers get the benefit of lower future prices in return for the NSP being able to earn extra profit in the current period. So the basic framework has *incentive properties* even if it does not have specific incentive schemes in place.

However, without specific incentive design, the incentive strength of cost savings or overruns varies between different years of a price control period. This is known as periodicity, and regulators have long been concerned that it could drive an inefficient cyclical spending pattern that is not in customers' interest. Additionally, there has been concern that there may be materially different incentive strengths between opex and capex which may distort spending decisions. Accordingly, regulators including the AER have sought to address concerns regarding periodicity and differences in incentive rates by designing specific incentive schemes: "Our incentive guidelines

⁵¹ AER, Network performance report 2026, July 2026, pp. 20–21.

⁵² AER, Network performance report 2026, July 2026, p. 22.

⁵³ AER, 2025 Annual Benchmarking Report – Distribution network service providers, November 2025 and AER, 2025 Annual Benchmarking Report – Electricity Transmission Network Service Providers, November 2025

supplement the price and revenue cap framework to provide even incentives for efficiency through the regulatory period”.⁵⁴

The AER’s specific cost incentives are the Capital Expenditure Sharing scheme (CESS) and, for opex, the Efficiency Benefit Sharing Scheme (EBSS). Both are symmetric efficiency-sharing mechanisms, but they arrive at their sharing rates through different logic. The CESS is calculated by comparing forecast capex in the determination against actual capex in NPV terms. The AER calculates the cumulative efficiency gain/loss over the regulatory control period, applies a sharing factor to derive the NSP’s share, calculates the financing benefit or cost that has accrued to the NSP over the period, and nets this off to arrive at the CESS reward or penalty. The sharing factor itself is tiered rather than flat: a 30% sharing ratio applies to all efficiency losses (overspends), while efficiency gains attract 30% on the underspend up to 10% of the approved forecast capex allowance, with any underspend beyond that threshold sharing at 20%. This tiering was introduced following the AER’s 2021–23 incentive schemes review as a response to concern that a flat 30% rate over-rewarded very large underspends.

The EBSS’s rate is arrived at differently – it is not a specific percentage in the way the CESS is, but an outcome of the revealed-cost forecasting mechanism itself. The EBSS is intrinsically linked to the base-step-trend opex forecasting approach: actual opex in the base year becomes the starting point for the next period’s opex forecast, which passes efficiency gains through to consumers, while carryover amounts are added as a building block to the NSP’s revenue for the following regulatory period. Under this approach, the sharing ratio of benefits from any increase or decrease in opex emerges from the discounting/carryover weighting mechanics (which use the regulatory rate of return as the discount rate) applied against the base-year revealed cost. Historically, the AER used the ~30:70 EBSS split it observed at the time as the basis for setting the CESS’s 30% sharing ratio, but since then the value of the EBSS to NSPs has fluctuated as rate-of-return parameters have changed.

This fluctuation is important. A key rationale for designing specific efficiency incentives is to ensure a balanced incentive between capex and opex expenditures. The extent to which this is important depends on two factors.

The first is that there are clear opportunities to substitute between opex and capex and these opportunities are increasing with the rise of CER. Non-network solutions - payments to customers (or retailers, or generators/storage in the case of transmission) for them to use their resources in ways that benefit the network are an efficient substitute for capex in some cases, but limited take-up to date, despite the high penetration of CER in Australian networks, suggests these options are not being optimised. Even in the case of more traditional expenditure options, there is a balance between replacement and upgrade capex versus monitoring and maintenance opex.

The second is how easy it is for NSPs to allocate or apportion costs such as general overheads between capex and opex. Concerns about their ability to police the boundary between capex and opex was a material driver of Ofgem’s introduction of the totex approach (see below). ICT costs are also becoming increasingly material to NSP expenditure, and while hardware may be straightforwardly capex, there may be less clarity around software, especially as providers increasingly move to software-as-a-service. Some activities consist of a mixture of capex and opex. For example, Ausgrid’s 2024-29 proposal identified four expenditure programs that are a blend of opex and capex: CER, Cyber security, Enterprise Resource Platform and Customer Information Systems.⁵⁵ Collectively, these account for over \$400m of costs.

Note that incentives typically are intended to operate at the margins and so it is not necessary that all or most of an NSP’s cost base to be substitutable for there to be merit in formally equalising incentive rates.

There are two ways to seek to equalise efficiency incentives. The first is to attempt to directly equalise by ensuring the same incentive rate between the two types of expenditure. This is simply a matter of arithmetic. As noted above, when the EBSS and CESS were first used together, the CESS was fixed at 30 per cent partly in order to align with the strength of the EBSS. Changes in the rate of return mean the strength of the EBSS has fluctuated between around 20 per cent and 30 per cent.

In practice it is a simple matter of arithmetic to set the EBSS at a fixed value, and thus equalise it to the CESS. The AER would just have to calculate the net present value (NPV) of opex saving (or overspend) at the end of the

⁵⁴ AER, Draft decision - Review of incentive schemes, December 2022, p. 5

⁵⁵ Ausgrid, 2024-2029 Regulatory proposal, January 2023, p. 62

reset period and then make a revenue adjustment up or down in the next period to achieve the desired percentage incentive rate. This was Ofgem's practice before it moved to a totex approach (see below). Given this is a low cost solution there appears no reason why the AER should not apply it, even if it is uncertain how important incentive equalisation is in practice.

5.1.1 Totex approaches

The second approach is to adopt a total expenditure (totex) approach that seeks to sidestep the risk of differences between capex and opex by applying efficiency incentives to all costs together. A useful resource to understand in detail how totex approaches have been used by other regulators is a report prepared by Frontier Economics for the AEMC in 2017 examining totex frameworks.⁵⁶ Countries such as the Netherlands and Germany have been applying totex incentives for many years. Both continue to set separate ex ante opex and capex allowances, but the ex post incentives are applied to total expenditure. This goes some way to addressing issues with inefficient capex/opex substitution and also negates any attempt to allocate actual costs to one type of expenditure rather than another (although this could assist with obtaining higher allowances in the next reset period, depending on the method for determining ex ante allowances).

British regulators Ofgem and Ofwat have gone further still, implementing ex ante totex frameworks. While there is some consideration of expenditure along capex and opex lines for the purposes of benchmarking, for example, the allowance is based on an amount of total costs with a fixed percentage treated as "fast money" - recoverable in each year of the reset period and "slow money" - added to the RAB and depreciated over a weighted average asset life. Key to the proportional allocation is a financeability assessment, which was already a component of these regulator's assessment before they adopted a totex approach.

Were the AER to seek to apply such an approach, it would require changes to the rules which currently specify that the AER must make an allowance for each of capex and opex. The AER has also only used financeability in a very limited way (as a cross check in its rate of return instrument process) and would need to develop its financeability assessment further.

Admittedly, it is unclear both the extent of any capex bias and the driver for such bias. As discussed in section 3.5 above, NSPs' penchant for control may be a stringer factor than relative incentive strengths, or there may be deep-rooted cultural organisation biases that are hard to shift. In this case, the directive approach discussed in that section may be a necessary circuit-breaker. Even if this is the case, though, either incentive rate equalisation or totex implementation are low regrets reforms that would at least test whether incentive rates play a role.

5.2 Other incentives

Ensuring service quality levels are maintained – and improved when it is cost-effective to do so – are a useful counterbalance to the risk that efficiency incentives drive networks to underspend and allow service levels or network reliability to degrade over time. Performance based incentive schemes include: the Service Target Performance Incentive Scheme (STPIS) for service performance and two that only apply to distribution networks: the Customer Service Incentive Scheme (CSIS) and the Demand Management Incentive Scheme (DMIS).

5.2.1 DMIS

The DMIS provides DNSPs with a financial reward for undertaking NNO projects that defer or avoid network expenditure. The scheme operates by allowing a network to earn an incentive payment of up to 50 per cent of the NNO project cost capped at the estimated net benefit of the project. The total financial incentive that a DNSP can accrue under the DMIS across all NNO projects is capped at 1 per cent of the DNSP's allowed revenue for that year.

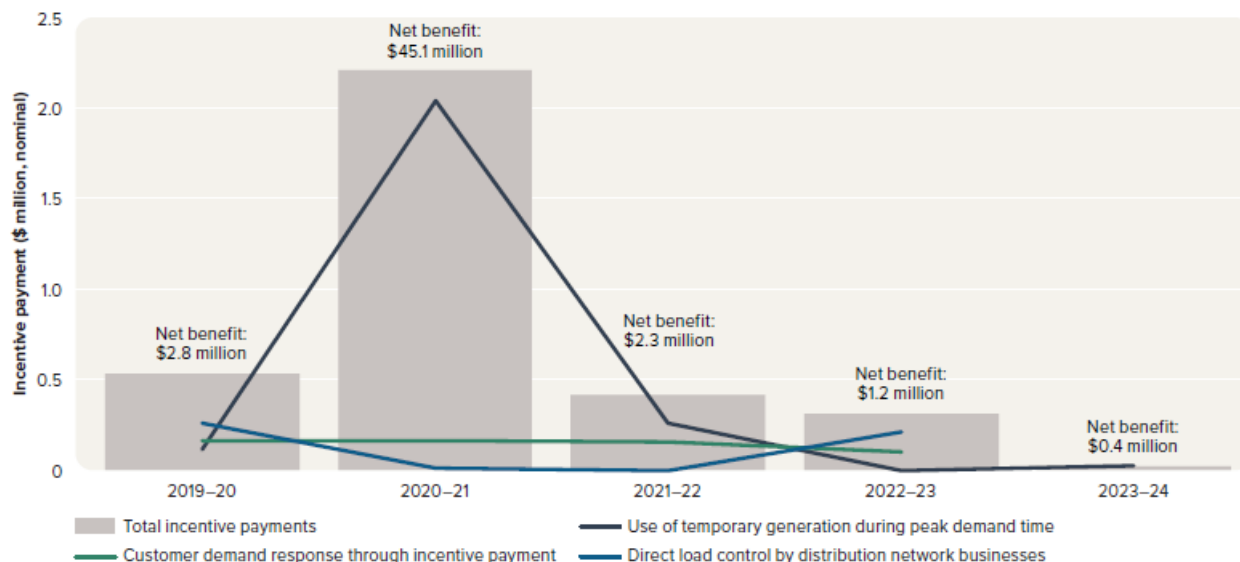
According to the AER, DNSPs earned \$3.5 million under the DMIS in five years up to and including FY2024, while delivering an estimated \$52 million in benefits.⁵⁷ By implication this means that projects on average had a cost/benefit ratio of around 7.5:1 (assuming the cost was double the incentive payout). It's improbable that the next best opportunities would not have had a significant net benefit and while some of the benefits may not be

⁵⁶ Frontier Economics, Total expenditure frameworks, December 2017

⁵⁷ AER, State of the Energy Market 2025, p105

realisable by DNSPs, the premise is that the projects allow DNSPs to defer replacement or augmentation capital expenditure. Given the relative sharing rates of the DMIA (50:50) and the CES (70:30 to customers) it seems unlikely that the DMIA is constrained by a lack of cost-effective opportunities, whether measured by DNSP exposure to costs and savings or on an overall cost-benefit basis. The scheme is clearly also not constrained by the allowed revenue cap since a cumulative \$3.5m payout is a fraction of the 1 per cent cap.

Figure 1: Funding of demand management innovations – electricity distribution networks



Source: AER State of the Energy Market 2025

As Figure 1 above shows even the modest expenditure on the DMIS is concentrated in one year. The broad description of qualifying activities: use of temporary generation, direct load control, and incentives for demand response are not especially groundbreaking and as such not especially risky to implement. It's hard to avoid the conclusion that the DMIS has failed to deliver anything other than a small fraction of the available demand management on the NEM, especially in the light of the rapid growth of CER. Potentially a more effective way to galvanise participation would be to restructure the incentive to assume a base level of demand management, with penalties for failing to meet that level and rewards for exceeding that level. A modest amount of ex ante expenditure could be allowed to reflect a plausible cost to meet the target, with costings based on the projects delivered to date.

The DMIS is complemented by a Demand Management Innovation Allowance (DMIA). This has been more successful in terms of eliciting DNSP participation, with \$9.87 million claimed in FY2025 alone, or more than DMIS expenditure of \$7m over five years. This is because it is risk-free money, being a use-it-or-lose-it allowance. It would be worth assessing how innovative projects really are, noting that a relatively low amount is on offer per network per year, or whether they should simply be expected to be delivered by DNSPs under business-as-usual.

NSPs' risk aversion was on display when the AER consulted on the form of the DMIA. Among the options were competitive bidding options, both for market-facilitated R&D and ground-breaking R&D. NSP stakeholders had a highly negative response to these options. As the AER noted: "Distributors and demand management providers particularly valued certainty and a low administrative burden"⁵⁸ – in other words, low risk and low accountability.

5.2.2 STPIS

The STPIS has been a source of significant additional revenue for electricity distribution networks. While consumers have enjoyed reliability improvements, which has driven the incentive payments, the AER cannot be sure that the reliability improvements would not have happened in any case. Presumably, if they are incremental improvements, NSPs had to incur extra costs not in their business plans to achieve them. Yet, NSPs have generally

⁵⁸ AER, Explanatory statement - Demand management innovation allowance mechanism, January 2026, p15

outperformed on the efficiency side as well. Unsurprisingly, consumers may wonder how they can tell they are getting value for money for these incentive payments. The AER should examine opportunities to tighten STPIS targets with the expectation that outcomes will be closer to a net payment of zero, or that NSPs that perform well on the STPIS are performing less well on efficiency incentives (because it is more cost effective for them to improve reliability than to make extra efficiency improvements).

In Transmission the market impact component (MIC) has been suspended due to TNSP complaints that they should not bear the risk of congestion on their networks. Whether the MIC is well-calibrated is open to question, but it illustrates an additional source of asymmetry that NSPs can lobby for incentives to be removed where they are a net cost but are happy to respond to incentives where they produce a net gain.

5.3 Implications for future approaches to network regulation

As discussed in section 5.1 above, equalising incentive rates between capex and opex – whether through simple arithmetic equalisation of the EBSS and CESS, or a more thoroughgoing move to a totex approach – is not a panacea, but each represents a comparatively low-regrets reform that is worth pursuing on the current evidence. A totex approach would require a rule change, given the NER's current requirement to set separate capex and opex allowances, and its adoption should be accompanied by monitoring of whether it demonstrably reduces the perceived bias toward capex identified above.

Other incentive schemes should be oriented towards delivering the transition and incentivising behaviour and outcomes that consumers value. They should continue to be directly controlled by the AER, with incentive rates and other parameters set and adjusted centrally to ensure they deliver genuinely symmetrical outcomes for NSPs, rather than being left to default settings that in practice reward one direction of performance more than the other. That is, NSPs should be exposed to penalties for not meeting the incentive baseline as much as they can earn rewards for beating the standards. This means that baselines for, say, demand management, must be set above zero, so they are no longer opt-in for NSPs, but are treated as a core activity.

6 Engagement

Stakeholder engagement and in particular consumer engagement has been a growing feature of the regulatory framework. The AER set out its expectations in the Better Resets Handbook in 2021, and many networks have invested significant resources into consumer engagement. The AER also runs a Consumer Challenge Panel (CCP) which independently reports to the AER on the quality of a network's engagement process

The value of consumer engagement includes:

- In a period of heightened change and uncertainty there should be greater scope for consumer preferences to play a role in the direction of system development.
- Consumers are the owners of CER and so their input is necessary to understand how best networks should interact with CER and reward CER for contributing to essential goals
- Consumers are best placed to comment on issues of affordability of energy prices, and equity in how tariffs are designed to share network costs across different customer groups
- Consumers are best placed to indicate the quality of service they expect networks to provide to them.
- Consumer views on discretionary expenditure are essential to understand the value they place on what that expenditure delivers (given they are ultimately paying for it).
- Consumer support – where demonstrable - should be a fundamental element in any proposal capable of achieving an early signal pathway or other fast tracking.

Accordingly, engagement is an important component of the energy transition and is the only authentic way to embed consumer preferences into the proposal. It's unlikely to ever be a full substitute for AER review. But engagement should be retained as a core feature and all parties should look for ways to enhance its impact.

6.1 Issues with current model

There are many aspects of engagement that could be explored to maximise its impact. Some of these – such as the specifics of how networks recruit participants, workshop format, how proposals are presented, likely involve a level of detail beyond what the AEMC will be considering in the Review. However, there are some elements of the regulatory framework that can be addressed to assist effective engagement:

Process timetable issue a): Framework and Approach consultation and (provisional) decision occurs very early in process. This typically allows for very limited engagement and there is often no CCP in place to observe and report on what engagement does occur. While some elements of Framework and Approach are relatively uncontroversial, the transition is likely to drive changes in service definitions and also raise issues about the appropriate form of control. Consumer views are relevant and important to both of these.

Process timetable issue b): There is a very short period between draft decision and revised proposal. While the amount of work an NSP has to do in order to respond to the draft decision varies, an ambitious NSP with multiple discretionary projects is likely to have a lot of work to do. Discretionary projects are more likely to be novel and their rationale untested with the AER (or the threshold for acceptance will be less clear) and so are at greater risk of being cut back or rejected in the draft decision. This in turn means they are at greater risk of being withdrawn even if they have consumer support, and the time and scope for further engagement is extremely limited.

Proposal assessment - There is a lack of clarity regarding the interaction between consumer preferences and the AER's "prudent and "efficient" assessment criteria. This often manifests in a consumer-supported project being rejected in full rather than having its expenditure trimmed. While it's important for any project that the AER should be satisfied that the proposed expenditure is consistent with prudence and efficiency, this approach contrasts with how the AER treats say a repex program. If the AER considers the proposed expenditure on repex does not represent the prudent and efficient level it cuts the amount back rather than rejects it altogether. A point of difference may be that because repex is a standard activity and typically highly material, the AER has developed a set of tools to evaluate repex and to derive a substitute figure, whereas it has not had the opportunity to do so for ad hoc discretionary projects. Nonetheless the upshot is that projects that the network has established has consumer support and willingness to pay for often get dropped or rejected rather than rescope for greater prudence and efficiency. This undermines the purpose and value of the engagement.

Accountability gap – There is a risk of a lack of accountability for discretionary projects, such as proposals to uplift customer service levels. While BAU activities such as repex have an element of built in accountability – if an NSP doesn't carry out its repex programme it risks breaching reliability standards, paying STPIS penalties and making Guaranteed Service Level payments (GSLs) where relevant. By contrast, many discretionary projects that are seeking to deliver something over and above legislative requirements - by their nature do not have these inbuilt accountability safeguards. To NSPs' credit, they are often open to including accountability safeguards in their proposal, such as proposing capex as use-it-or-lose it, or committing to report on progress to a customer panel. However, these are voluntary commitments and don't carry the weight of AER enforcement. A clearer regime for introducing robust accountability to discretionary projects is necessary.

Informal feedback – The AER's current approach is to observe some elements of the Engagement program, but typically not to offer any views on the prospects for acceptance of elements of the proposal. While the AER can only make a *decision* on the actual proposal put to it, there is a missed opportunity for AER to engage in constructive dialogue with the network and engagement participants before proposal lodged. At a minimum this could help manage expectations, but more likely it would assist in winnowing out poorly justified projects and strengthening the case for the better projects.

Lack of AER engagement – The AER relies on the network to carry out engagement. Consumers and other stakeholders can of course participate in AER consultations by making a submission, but this is a different kind of engagement and is typically confined to consumer representative groups (on the consumer side). Information asymmetry plays out in network engagement even when the NSP is sincere and well-intentioned in its engagement, and so the AER could seek to validate the outcomes of network engagement via periodic targeted engagement of its own.

6.2 Implications for future approaches to network regulation

Of the two responses suggested by the discussion above, resourcing the AER to carry out its own targeted engagement, and to participate in constructive dialogue with networks and engagement participants through the reset process, should be the priority. This would allow the AER to independently test and validate the outcomes of network-led engagement – including in situations where an NSP's engagement is entirely sincere and well-intentioned but still affected by the underlying information asymmetry – and to signal its own views on emerging proposals before they are locked into a final proposal.

Changes to the regulatory timetable to accommodate more engagement, particularly to lengthen the currently very short period between draft decision and revised proposal, would also help, by addressing the amount of time available for engagement.

7 Appendix A: Implications of this report for the Package 2 Consultation paper

Table 3: Summary of responses to Package 2 Consultation paper questions

Question	Comment	Section ref
Question 1 Prioritisation framework for the Review		
Do you have any feedback on our approach to the Review, including the proposed prioritisation framework?	N/a	
Question 2 Are changes required to the revenue determination process?		
1. Do you think there are problems with the amount of time and resources the current revenue determination process takes? Are there any other ways to improve the efficiency and effectiveness of the revenue determination process we should consider?	The process is lengthy and costly, although the figure quoted in the Consultation Paper is a total cost, not an incremental cost. Presumably, some of the planning, analysis and engagement costs would be incurred anyway. In any case, the driver of these costs is the need for each NSP to robustly justify its expenditure plans and for the AER to carefully scrutinise the plans. This appears unavoidable under a low NSP risk, asymmetric framework, as the AER's assessment is the only bulwark for customers to be protected against excess costs.	3
2. Do you think any changes should be made to streamline or otherwise improve the efficiency of a. the F&A stage for TNSPs and/or DNSPs? b. the NSP development of regulatory proposal stage? c. the revenue determination stage? If so, please explain what those changes are and the expected benefits.	Because the F&A stage occurs early in the process, there is limited engagement. This stage may become more important as the transition drives a need for new service classification and greater consideration of the form of control. While the framework protects the NSPs from risk to the degree it does, it is hard to see an alternative to a high level of scrutiny by the AER as the key source of protection for consumers against overpaying. This is the driver for a resource-intensive process.	6.1 3
3. Do you think more fundamental changes are required to the revenue determination process? If so, please explain what those changes are and the expected benefits.	Currently, the framework is very low risk for NSPs. This is somewhat reflected in the rate of return, although it is hard to draw a clear link due to data limitations. Given the transition is driving greater uncertainty, this uncertainty has been and will continue to manifest as increased risk passed through to consumers unless there are fundamental changes. Changes can broadly take either or both of two forms: greater accountability and risk bearing by NSPs and/or greater direction from the	3.4 3.7

Question	Comment	Section ref
	NER and the AER. The benefits of both are the reduction in risk exposure for consumers.	
4. Do you think changes should be made to the regulatory determination timetable? If so, please explain what those changes are and the expected benefits.	The period between draft decision and revised proposal is very short. This reduces the scope for greater engagement, and increases the likelihood that customer-supported projects are shelved. The benefits of a longer period would be an opportunity for greater customer/stakeholder input into the revised proposal.	6.1
Question 3 Are changes required to improve the quality of expenditure forecasts		
1. Do you consider there are any problems with the current approach to capex and/or opex forecasting and the associated incentives that we should consider? If so, please explain what those problems are.	The propose respond model exacerbates the NSPs' information advantage and creates an incentive to over forecast. As uncertainty increases, the scope for material error in forecasts (of costs or of factors underlying costs, such as demand) grows.	4
2. Do you consider changes are needed to the revenue determination process, the incentive framework, or both, to support better quality capex and opex forecasts and more complete information from NSPs? If so, please explain what those changes are.		
3. Are there any methods used in other regulatory regimes to incentivise better quality expenditure forecasts that you think we should consider as part of the Review? IF so, please explain what those changes are and the expected benefits.	Menu regulation approaches are worth exploring in this context.	4.4
Question 4 Are changes required in how consumer preferences are reflected in the revenue determination process?		
1. Are there issues with the current approach to consumer engagement in the revenue determination process?	See discussion in section 6	
2. Should changes be made to how consumer preferences are identified, represented and reflected in the revenue determination process?	See discussion in section 6	
a. Is there a need to clarify how consumer views should be used and are there certain topics where consumer views are most relevant?	There is no need to rule topics in or out for whether they are suitable for engagement.	
b. Could retailers play a more prominent role in representing consumer preferences in the revenue determination process, recognising	Retailers are not consumers and it is not reasonable from either retailers' or consumers' perspective to expect retailers to represent consumers.	

Question	Comment	Section ref
their ongoing and evolving role in managing complexity for consumers?		
3. Are there any other methods for considering consumer preferences, including from other regulatory regimes, that you think we should consider as part of this review?	n/a	
Question 5 Are changes required to levelise incentives between capex and opex?		
1. Does the current framework provide a level playing field for all technology types at both the transmission and distribution level?	It seems unlikely judging by the low incidence of non-network outcomes being selected in RIT-T and RIT-D processes.	4.4
2. Do you think that the current framework incentivises NSPs to favour capex- over opex-based solutions? If so, what are the most important factors that drive this outcome?	It seems likely that this is the case, given Australia has very high levels of CER deployment but low levels of network integration or rewards to CER for providing network support. The cause could be financial incentives, a preference for control or other organisational cultural factors.	
3. Do you have any observations on how interactions between the CESS and EBSS may impact efficient NSP choices in relation to capex and non-network solutions?	It seems straightforwardly the case that if the relative strengths of the incentives are not equal, then that would impact efficient NSP choices.	5.1
4. Do you have observations on the effectiveness of the DMIS in driving non-network solutions? Do you have any views on improvements or alternatives to incentivise NNOs?	Given low levels of non-network solutions, it seems on the fact of it that the DMIS has not been effective.	5.2.1
How should we approach DSO incentives through this Review?		
1. What are your views on how the need for new DSO incentives should be considered?	Incentives should be calibrated so as to be symmetrical, that is there should be equal chance of penalties or rewards. This is challenging to achieve when an incentive is first implemented, and requires the regulator to determine incentive parameters. In general, NSPs can decide for themselves whether they want to respond meaningfully to incentives. So, if it's clear that particular outcomes are required from DSOs, they should be mandated rather than incentivised.	5.3
2. How broadly should the concept of the 'whole system' be defined for DSOs? Please provide examples of the benefits that would fall within your preferred scope and explain why it would be appropriate for a DSO to be incentivised to maximise those benefits.	n/a	

Question	Comment	Section ref
3. What level of quality and depth of coordination should DSOs be responsible for delivering? Should these outcomes be achieved through obligations, incentives or a combination of both? Where incentives may be appropriate, which aspects of coordination should they target?	Obligations and expectations on DSOs should be carefully specified. Desired system outcomes may not be predicated on DSO control or direct co-ordination, but instead may be delivered more efficiently and effectively by consumer, retailers and other parties responding to signals sent by the DSO.	
Question 7 We are interested in stakeholders' views on an incentive mechanism to support efficient network utilisation		
1. Do you consider that there should be more explicit incentives established to drive efficient network utilisation by NSPs?	Efficient network utilisation should be targeted. It is unclear whether this requires or is best achieved through an incentive on NSPs to increase utilisation. A more directive approach may be more effective if NSPs appear unwilling to be exposed to the risks entailed in responding to network utilisation incentives.	3.6
2. How could such a mechanism be designed and how could measurement limitations be addressed?	Incentives should be calibrated so as to be symmetrical, that is there should be equal chance of penalties or rewards. This is challenging to achieve when an incentive is first implemented, and requires the regulator to determine incentive parameters. In this case, the first step is to ensure it is clear what the appropriate utilisation metric should be.	5.3
3. Are there other options to drive efficient utilisation that you would like the AEMC to consider?		
Question 8 Are changes required to better incentivise network innovation?		
What are your views on the effectiveness of the incentive framework for network innovation?	It is not effective, nor is it likely to be given NSPs' risk profile. Innovation is inherently risky, and so innovation resources are typically made best use of when the party carrying out the innovation bears the risk of failure as well as the rewards for success.	3.6
What improvements can be made to this framework to drive greater levels of innovation?	Likely none, regulated networks are not the place to look for innovation. Deployment of successful innovations proved up by others is important to monitor and drive, but does not merit special incentives.	3.6
Question 9 Does the framework appropriate allocate risk given the changes underway?		
1. Do you consider that some sources of uncertainty are increasing in the context of the energy transition? Given the changes	Yes, this is clearly the case, and the consultation paper appears to recognise this.	3.1

Question	Comment	Section ref
underway does the framework appropriately allocate risk between NSPs and consumers?	The framework allocates risk mostly to consumers as discussed in the response to previous questions	
2. Are the various intra period and ex post adjustment mechanisms appropriately targeted and fit for purpose?	It's pragmatic to have such adjustment mechanisms but they reflect the asymmetry of the framework in NSPs' favour.	4.3
Question 10 Does the framework appropriately enable anticipatory investment?		
1. Does the current framework appropriately balance the costs of investing too early against the costs of investing too late, and does it support investment at the point that maximises long term consumer value?	See below.	
2. Are there aspects of the regulatory framework that act as a barrier to efficient anticipatory investment? Please provide evidence or case studies.	It's unclear whether we have a robust method for determining whether anticipatory investment is efficient that could be applied in the framework. How could consumers be confident in NSP decisions to make anticipatory investments if NSPs aren't accountable for those decisions?	3.4
<i>Does the RoRI enable appropriate compensation for risk within the context of the regulatory package as a whole?</i>		
1. Are emerging transition-related risks systematic or business-specific in nature?	There is not a neat distinction between systematic and business-specific risks. Any risk evaluation also needs to take account of the substantial risk mitigations built into the regulatory framework.	3.3
2. Are TNSPs and DNSPs facing increasingly different risk profiles and, if so, are those differences relevant for the RoRI?	It's a plausible hypothesis that TNSPs and DNSPs face different risk profiles. The question is what tools the AER has to recognise this even if the RORI framework allowed them to.	3.3 Appendix B
3. Does the current RoRI framework provide sufficient flexibility to reflect changes in systematic risk over time?	The issue is not so much flexibility as the fact that the AER does not have a methodology or data that provides it with a robust basis for reflecting changes in systematic risk over time or between different network types	3.3 Appendix B
Question 12 Do you agree with our proposed assessment framework?		
1. Do you agree with the proposed assessment criteria? Are there additional criteria that the Commission should consider or criteria included here that are not relevant?	n/a	

Appendix B: tools for measuring network systematic risk

The AER sets the allowed rate of return using the Capital Asset Pricing Mechanism (CAPM). In principle, the rate of return is calibrated to the systematic risk of an Australian energy network as compared to the Australian market (i.e. the ASX). This component of the CAPM is known as beta, and historical betas can be estimated by measuring the volatility of energy network stock prices relative to the market. However, the AER has a growing practical problem with beta estimation.

It has historically relied on ASX-listed energy network businesses to obtain an estimate of beta. The number of listed companies that could be considered energy network businesses has declined over the years. Spark Infrastructure delisted in late 2021 and Ausnet delisted in early 2022 when they were bought out by private investors. This left APA as the only domestically listed comparator, and there are question marks over whether this company is fully representative of an energy network business. Most of its pipeline assets are not price regulated and as the ERA (Economic Regulation Authority) has noted “it has also changed its business strategy and has diversified into areas such as renewable energy generation”.⁵⁹

Accordingly, the AER (and ERA in WA) have incorporated data from overseas energy businesses in their estimation of beta. It’s beyond the scope of this report to examine this approach in detail, but suffice to say that this approach entails numerous assumptions about the comparability of overseas businesses and overseas stock markets.

The domestic comparators, such as they are, also typically own all or part of several energy networks. For example:

- AusNet owns gas distribution, electricity distribution and electricity transmission
- APA owns gas distribution, gas transmission and electricity transmission (interconnector)
- Spark owns electricity distribution and electricity transmission

Accordingly, the domestic data is not amenable to disaggregation of beta estimates into the different energy network types (gas/electricity, transmission/distribution). Relying entirely on international data for such a disaggregation is also inappropriate and may not be feasible as international businesses often own multiple network types (or non-network businesses) too.

The AER has also rejected the concept of beta estimation from “first principles”, i.e. from an examination of the systematic risks to which networks are exposed.⁶⁰ Given that there is no widely accepted methodology for doing so, this is unsurprising. It also means that the AER does not have a methodology for making forward-looking adjustments to beta if it determines that changes to the framework (or projected changes in the operating environment) lead to a change in the level of systematic risk.

This means that consideration of whether or not electricity transmission may theoretically have a higher systematic risk than electricity distribution is not a reason to seek changes to the parts of the NEL that govern the Rate of Return Instrument (RORI). The AER does not have the means to robustly differentiate between the two network types when it comes to estimating beta.

However, there could be merit in reviewing these sections of the NEL to address rigidities in the current requirement to set a single binding rate of return every four years.

Other parameters in the Rate of Return are potentially more amenable to differentiation by type of network. The return on debt is one. A key debate in the current Rate of Return review is whether or not to change the return on debt from a simple trailing average to a weighted trailing average with the weighting determined by the annual capex requirement of each NSP. The driver for considering these changes is that the ISP may require some TNSPs to invest capex at a far faster rate than in the past and at a high level relative to their current RAB. In such circumstances “where interest rates are materially above the return on debt from the simple trailing average, this

⁵⁹ ERA, Explanatory statement for the 2026 draft gas rate of return instrument, Attachment 5: Equity, July 2026, p. 40

⁶⁰ AER, Draft 2026 Rate of Return Instrument Explanatory Statement, May 2026, p40

could result in required essential projects being delayed or not proceeding. In the alternative, where interest rates are materially below the return on debt from the simple trailing average, it could incentivise inefficient over-investment on large projects”⁶¹. In 2022, the AER’s analysis of variability in debt-raising requirements indicated that only two TNSPs and no DNSPs had growth rates in excess of 5 per cent, and that growth rates below this were not considered material⁶². In other words, the AER was obliged to consider the merits of a change to the RORI for all networks due to an issue that was only material for some TNSPs.

Other implications of large capex programs for the rate of return could be on the benchmark credit rating (which would impact the return on debt) and/or gearing. Accordingly, there could be merit in the AER being more easily able to vary these parameters between networks where circumstances justified it.

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⁶¹ AER, 2026 Rate of Return Instrument, Discussion paper, August 2025, p. 21

⁶² AER, 2022 Rate of Return Instrument, –Draft explanatory statement, June 2022, p. 228

