AEMC
Australian Energy Market Commission

Australian Energy Market Commission

REVIEW

Consultation paper

Electricity network regulation review - Package 2

13 August 2026

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the Traditional Custodians of the many different lands across Australia on which we live and work. The AEMC office is located on the land of the Gadigal people of the Eora nation. We pay respect to all Elders past and present, and to the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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Summary

1 The way we regulate electricity networks matters for consumers. Network costs typically account for between a third and half of customers' final bills and electricity networks are critical enablers of a growing number of services that provide value to end users. Electricity networks are also, in general, natural monopolies and are therefore economically regulated. The effectiveness of this regulatory framework is fundamental to delivering better consumer outcomes, shaping the affordability, quality and reliability of the services consumers receive.

2 The energy transition is driving significant change across the National Electricity Market (NEM), reshaping the role of electricity networks and the way network service providers (NSPs) should be regulated. The regulatory framework must adapt to ensure consumers benefit from these changes while remaining protected from new and evolving risks. Key developments and their implications for the network regulatory framework include:

- **Rapid growth in consumer energy resources (CER)**: the ongoing growth in CER creates opportunities for consumers to benefit, including by using coordinated CER to avoid or defer network augmentation as well as to provide bulk power supply and system security services. This provides the potential to reduce system costs and return more value to consumers.
- **Increasing wind, solar and storage at grid scale**: major transmission developments often require greenfield development, which creates new challenges and risks. Non-network options are increasingly viable at both the distribution and transmission level, presenting opportunities to reduce costs to consumers.
- **Rapid but uncertain demand growth**: greater levels of uncertainty raise questions about the allocation of risks between consumers and network businesses, the appropriate use of intra-period adjustment mechanisms, and the effectiveness of incentive mechanisms set with reference to ex ante forecasts.
- **Heightened sensitivity to electricity price increases**: these changes in the NEM are occurring against a backdrop of ongoing cost of living pressures, heightening consumer sensitivity to further energy price increases. Realising the benefits of the transition while ensuring consumers pay no more than necessary for safe, reliable and secure energy services, is critical to maintaining public confidence and social licence for the energy transition.

3 The scale and pace of change across the energy system highlights the need to revisit the regulatory framework for electricity networks in the NEM. We have therefore commenced this Review to ensure the framework remains fit for purpose and continues to support efficient, consumer-focused outcomes as the energy transition progresses.

We are undertaking the Review in two packages

4 We are dividing the Review into two packages to support timely decision making and to manage interactions with other related rule changes.

5 Package 1 will focus on how different services provided by NSPs are classified, the ring-fencing and other tools currently used to ring-fence regulated network services from contestable services, and the treatment of assets used to provide regulated and unregulated services. We initiated Package 1 with a separate consultation paper on 25 June 2026. That consultation paper also initiated related rule changes dealing with ring-fencing and service classification for EV charging infrastructure from Nexa and Energy Networks Australia, respectively.

6 Package 2 will consider how the regulatory framework seeks to promote consumers' interests in

the provision of regulated services by NSPs. This consultation paper is the first step in Package 2.

7 We are assessing the framework through these separate packages to facilitate a structured process to articulate the various objectives of the framework, describe how individual component parts work, and identify and agree issues for further exploration. We recognise that in practice many parts of the framework impact each other and we will consider these connections throughout the Review.

8 We are seeking stakeholder views on how these aspects of the framework are performing and where changes may be required to promote better consumer outcomes. This work will inform further consultation and recommendations on the future shape of the electricity network regulatory framework in the NEM.

This paper seeks your views on whether changes are needed to the economic regulatory framework for NSPs in the NEM

9 This paper considers three key elements of the economic regulatory framework and seeks your views on whether changes are needed to improve consumer outcomes:

- **Revenue determination process** – how an NSP's regulated revenue is set for a forward regulatory period
- **Incentives** – how the framework aligns NSPs' decisions and behaviours with consumers long-term interests, and
- **Risk allocation** – how risks are allocated between NSPs and consumers, and how NSPs are compensated for the risks they bear under the framework.

10 Our starting point is to consider changes within the existing ex ante incentive-based regulatory framework. We consider this approach is likely to support more timely implementation of reform and have not identified a compelling case for moving away from the overarching framework at this time. This does not preclude significant change. Rather, we are exploring whether substantial reforms can be achieved within the existing ex ante regulatory model.

11 Our initial identification of issues for further exploration is based on a prioritisation framework developed for this Review to ensure we balance depth of analysis with timeliness of delivery. The policy prioritisation framework is based on the following criteria:

- ***Materiality*:** How significant is the issue and how strong is the evidence base? How much do consumers stand to benefit from addressing this issue?
- ***Implementation feasibility*:** Are other practical solutions available? Can solutions be implemented by the AEMC through NER changes, or do they require agreement and coordination from other actors (e.g. Energy Ministers)? If coordination is required, how difficult will it be?
- ***Other processes*:** Is there another rule change process already underway, or are there formal review processes already established, that are better placed to review this aspect of the framework and efficiently address the identified issue?
- ***Separability*:** Is this an issue that is difficult to consider in isolation such that it should be considered through a holistic review of this nature? Or can it be separated and progressed through a stand-alone process that would likely lead to faster resolution of the issue (e.g. a rule change or other process)?

12 We have used this prioritisation framework to identify the issues that we propose for further exploration set out below. We intend to apply the same framework when considering whether to

include any additional issues identified by stakeholders through the consultation process.

Are changes needed to the revenue determination process?

13 NSPs are regulated monopolies. Under the NEM's ex ante regulatory framework, the revenue NSPs can recover from consumers for regulated services is determined in advance through a revenue determination process based on the building block approach.

14 A key objective of the revenue determination process is to determine the revenue allowance that a prudent NSP would require to efficiently invest in, operate and provide regulated services over the forward five-year regulatory period. This includes the allowance that is required for capital and operating expenditure, both of which can have a material bearing on the regulated revenue that NSPs can recover into the future.

15 The revenue determination process is currently administered using a multi-stage propose-respond approach. The process requires an NSP to submit its regulatory proposal to the Australian Energy Regulator (AER), who must then determine the revenue allowance for the forthcoming regulatory period, having regard to this proposal, as well as consumer and other stakeholder feedback. Subject to any intra-period adjustments and ex post mechanisms (discussed below), the AER's final determination on an NSP's revenue allowance is binding for the regulatory control period.

16 The process is intended to support robust and transparent decision making, while ensuring outcomes reflect consumers' interests and preferences. This is important because regulatory determinations affect a wide range of individuals, businesses and organisations. At the distribution level, CER is also changing the way consumers interact with the electricity system, including by enabling households and businesses to make more active choices about how and when they consume and export electricity. As a result, understanding consumer preferences is an increasingly important input into both NSP regulatory proposals and AER determinations.

17 We propose to explore the following issues through the Review:

- **Efficiency of the revenue determination process:** The current revenue determination process is resource-intensive and can take several years to complete. It requires significant investment from NSPs, the AER, consumers and others. In their most recent regulatory determination cycle, TNSPs and DNSPs spent an estimated ~$190 m on a combined basis to prepare their regulatory proposals, engage with their customers and other stakeholders and participate in the various stages of the determination process. These costs are small relative to NSP's overall operating expenditure (collectively around $5.13 billion in 2025) but still matter as these costs are ultimately borne by consumers. We will explore if the process could be streamlined while maintaining robust regulatory oversight and stakeholder engagement.
- **Supporting good quality regulatory proposals and robust determinations:** One of the limitations of the ex ante approach is the information asymmetry between NSPs and the regulator. While the rules already allow the AER to scrutinise and, where appropriate, substitute expenditure forecasts, assessing future expenditure needs can be complex, particularly where uncertainty is high. The energy transition may increase this challenge, especially in relation to capital investment requirements. We will explore whether alternative approaches could help reduce information asymmetries, support better quality regulatory proposals and determinations, and ultimately lead to better consumer outcomes.
- **Ensuring consumer interests are effectively represented and reflected in regulatory proposals and determinations:** Engagement by NSPs with consumer representatives has improved over time, supported by changes to the National Electricity Rules (NER) and pro-active steps taken by the AER, NSPs, Energy Consumers Australia and Energy Networks

Australia. However, in our early consultation stakeholders have raised questions about how effectively consumer interests and preferences are reflected in regulatory proposals and determinations. We will consider whether the current framework provides appropriate opportunities for consumer input, how consumers can best be represented in the process (including the potential role of retailers) and whether consumer views are being effectively incorporated into regulatory outcomes.

Are changes needed to the incentive framework?

18 The regulatory framework uses incentive-based regulation to align the interests of NSPs with those of consumers. Financial incentives are designed to encourage NSPs to deliver regulated services efficiently while maintaining service levels that reflect consumers' preferences and expectations.

19 The framework is made up of a range of complementary incentives that are intended to operate as an integrated package. Some incentives are inherent to the ex ante framework. For example, where NSPs deliver services at a lower cost than their approved expenditure allowances, they can retain a share of those savings. This creates a strong incentive to find more efficient ways of delivering services, with consumers also benefiting through lower future costs.

20 The framework also includes a number of explicit incentive schemes, which have been introduced over time to correct or improve deficiencies in the framework. These mechanisms include:

- The **Efficiency Benefit Sharing Scheme** (EBSS): The EBSS shares any under- or over-spend of an NSP's operating expenditure (opex) allowance between consumers and NSPs. Without the EBSS, NSPs face declining incentives to reduce opex throughout the regulatory control period.
- The **Capital Expenditure Sharing Scheme** (CESS): The CESS has a similar objective to the EBSS but applies to capital expenditure (capex). Without the CESS, NSPs also face declining incentives to reduce capex throughout the regulatory control period.
- **Service Target Performance Incentive Scheme** (STPIS): The STPIS incentivises NSPs to reduce network interruptions and provide network reliability to a level that aligns with what consumers value and are willing to pay for. Without the STPIS, NSPs may be incentivised under the EBSS and CESS to reduce expenditure at the expense of service quality, below the level that consumers value.
- **Demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM)**: The DMIS provides an incentive for DNSPs to pursue non-network options (NNOs) by providing an incentive payment. It was introduced recognising that DNSPs may under-invest in NNOs because of potential incentives to favour network (capex-based) solutions over non-network (opex-based) solutions, as well as DNSPs' inability to capture any of the broader whole-of-system benefits that NNOs might produce, such as reduced wholesale generation costs. The DMIAM provides NSPs with an annual funding allowance to undertake research and development projects that explore innovative non-network approaches.
- **Small Scale Incentive Schemes**: The AER also has the ability to establish small scale incentive schemes. The AER has established two DNSP schemes under these provisions:
  - **The Export Service Incentive Scheme** (ESIS): The ESIS enables DNSPs to be rewarded for enabling customers to export electricity to the network at a capacity that reflects how much they value the service. It was introduced in recognition that NSPs may otherwise have an incentive to reduce export capacity available to consumers in order to reduce costs.

- **The Customer Service Incentive Scheme** (CSIS): The CSIS was established to incentivise DNSPs to provide customer service to a level of quality in line with what consumers value.

21 We plan to consider a number of issues regarding the adequacy of the incentive framework. In doing so, we will consider whether new incentive mechanisms may be required, whether any of the incentive schemes should be modified or removed and the interaction between the schemes under any proposed changes. The specific areas we will explore further include:

- **Incentives on NSPs to undertake opex relative to capex:** A potential structural bias from NSPs to preference capex solutions over opex solutions is a long-standing concern with the regulatory framework. The DMIS was introduced to overcome any potential capex-bias, but the scheme has had relatively limited uptake. There are likely a range of possible barriers to NNOs including: financial incentives for NSPs to preference capex in some circumstances, interactions between the CESS and the EBSS, and operational and risk allocation considerations. The impact of any barriers to NNOs are likely to have an adverse impact on consumer outcomes as NNOs become increasingly cost-competitive and viable at both the transmission and distribution level.
- **Changes to incentive arrangements for DNSPs to perform new and evolving distribution system operator (DSO) roles:** Energy Ministers agreed in December 2025 that DNSPs should be formally assigned DSO responsibilities. DNSPs are already undertaking many DSO responsibilities, and we will explore whether the current framework adequately incentivises DNSPs to perform these roles in a way that maximises consumer outcomes. In particular this will focus on the role of the DSO in promoting whole of system outcomes, and any other regulatory barriers to these outcomes.
- **Incentives to support efficient network utilisation:** Network utilisation is generally regarded as a measure of the efficiency and productivity of network infrastructure, noting there are various metrics that may be relevant. Network utilisation is a proxy for improved consumer outcomes because, all else being equal, it indicates an increase in the use of the network relative to a set level of investment. We intend to explore the value of strengthening incentives to increase network utilisation to efficient levels, which will include consideration of implementation challenges.
- **Incentives to innovate**: The framework creates relatively strong incentives for NSPs to pursue cost savings and outperform their expenditure allowances. However it is also in the long-term interest of consumers for NSPs to make investments now in order to reduce costs into the future, such as investing in research and development (R&D) and innovation. We will to consider changes to the framework that could strengthen incentives for both TNSPs and DNSPs to invest in R&D and innovation. This will include considering the ongoing role of the DMIAM.

Are changes needed to the way risk is allocated and compensated?

22 Electricity networks deliver essential services through capital-intensive, long-lived assets, the costs of which are largely sunk once investment decisions are made. This creates a regulatory risk for an NSP in that once it commits capital, it cannot easily withdraw or redeploy that investment if future regulatory decisions affect cost recovery.

23 This problem is addressed through an implicit regulatory compact between NSPs and consumers/regulators that is also established formally through components of the framework such as the revenue and pricing principles in the National Electricity Law (NEL). NSPs accept revenue and price regulation in exchange for a reasonable opportunity to recover efficient and prudently incurred costs, including a return commensurate with the risks they bear. This compact

is important for consumers because it supports efficient investment while protecting consumers from paying for inefficient costs.

24 Efficient risk allocation is central to that outcome. If NSPs bear risks they cannot efficiently manage, network investment may be discouraged, and consumers may face lower reliability or higher financing costs incurred by NSPs. If consumers bear risks NSPs are better placed to manage, they may pay more without receiving corresponding efficiency benefits. The framework should therefore allocate risks to the party best placed to manage, influence or absorb them.

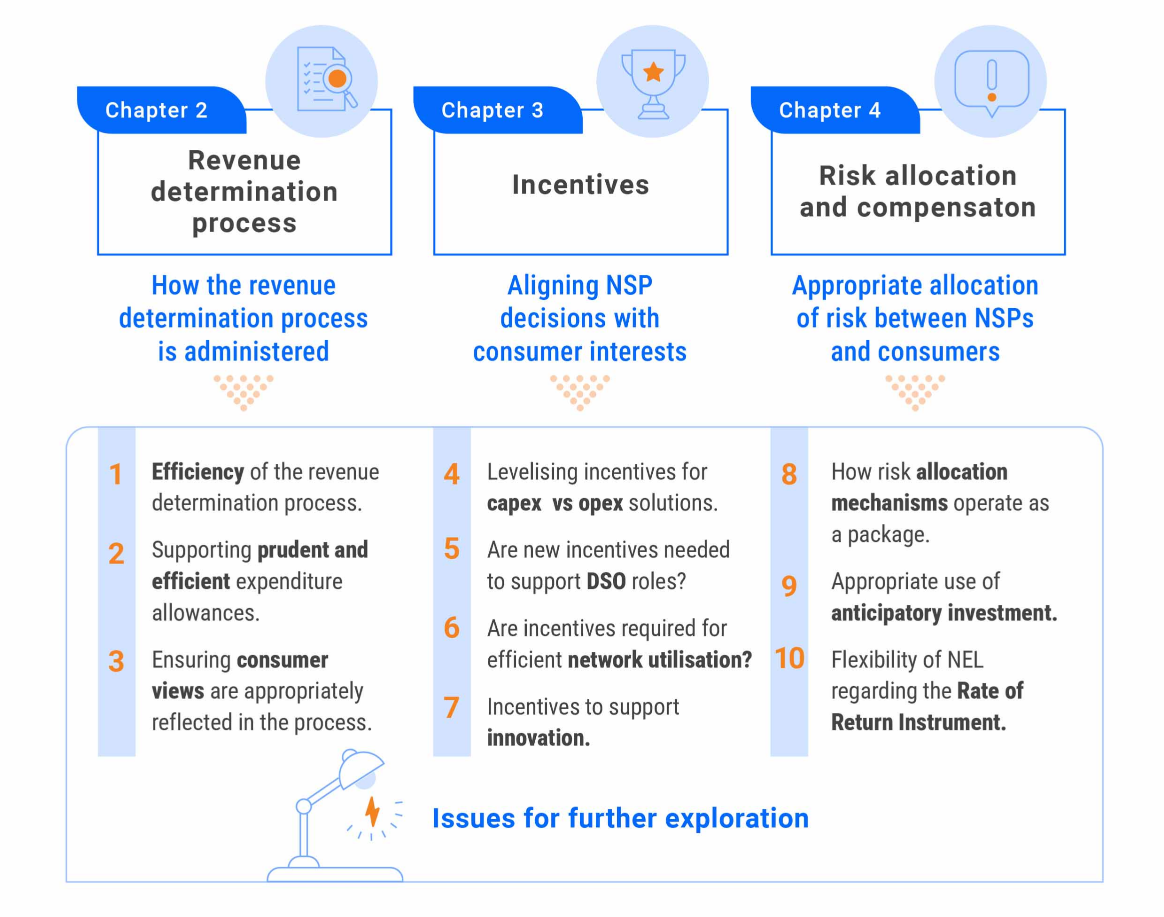
25 The framework allocates and shifts risks between NSPs and consumers through a range of mechanisms. These include the form of control (revenue vs price cap), intra-period adjustment mechanisms (such as cost pass throughs, contingent projects and reopeners), cost sharing ratios determined under the EBSS and CESS, and the regulatory asset base (RAB) roll-forward model combined with the ex post review. Systematic risk is compensated for through the regulated rate of return determined by the AER as per the Rate of Return Instrument (RoRI).

26 We propose to explore the following areas relating to risk allocation and compensation further as part of this Review:

- **The use of risk allocation mechanisms**. The energy transition is changing and potentially increasing some of the risks faced by NSPs and consumers, such as demand forecast risk. This raises the risks of under- or over-building network assets. NSPs are also increasing their use of intra-period adjustment mechanisms. This raises questions about the appropriate use and process for these mechanisms, as well as their impact on the overall ex ante incentive framework. As anticipated in our recent *Review of Pricing for a Consumer Driven Future*, we propose to explore whether the existing suite of risk allocation tools continues to allocate risk to the party best placed to manage it and whether risk allocation works across the framework in a cohesive way.
- **The appropriate use of anticipatory investment given the changes underway**. Anticipatory investment includes situations where an NSP incurs higher costs in the short term in order to achieve a more efficient total outcome over the long-term. Examples include undertaking upgrade works earlier than needed in order to achieve economies of scale and better overall efficiency of the works. Anticipatory investment may become more challenging or risky in the context of elevated uncertainty. Incentives created by the EBSS and CESS to pursue short-term efficiency savings may create further constraints. Conversely, in the context of expected increases in demand, it may present an opportunity to reduce overall costs to consumers.
- **The AER's flexibility in developing the rate of return instrument (RoRI) under the NEL**. The NEL prescribes the process that the AER must follow when developing the RoRI, which sets the regulated rate of return that NSPs receive. The NEL requires the same methodology apply to the rate of return for all TNSPs and DNSPs. We intend to consider the different challenges and risks faced by TNSPs vs DNSPs and consider whether these differences are (or can be) sufficiently accounted for using the risk allocation mechanisms mentioned above, or if a different approach to determining the rate of return might be warranted. In making our assessment we are cognisant of and plan to explore the practical challenges in determining appropriate rates of return for different entities as well as the legal implications that any change would likely involve.

27 These proposed areas of further investigation are summarised below in Figure 1.

Figure 1: Issues we propose to explore further through Package 2 of the Review



Source: AEMC

Five assessment criteria will help us assess potential reforms in this Review

28 Considering the National Electriciy Objective (NEO)[1] and the issues raised in the Review Terms of Reference, the Commission proposes to assess potential reforms using the following assessment criteria:

- **Outcomes for consumers:** Promoting the long term interests of electricity consumers is a central tenet of the regulatory framework and as consumers become more active in the electricity market, it is becoming increasingly important to ensure that the market is delivering the outcomes consumers expect. We therefore intend to consider the extent to which the proposed rule changes and reform options identified through the Review will promote consumer interests.
- **Emissions reduction:** Network regulation can have a direct impact on consumer and NSP behaviour and the achievement of emissions reduction targets. We intend to consider the impact that the proposed rule changes and any reform options identified through the Review may affect the achievement of jurisdictions' emissions reduction targets.

1 Section 7 of the NEL.

- **Principles of market efficiency:** The regulatory framework is intended to promote economic efficiency in the provision and use of electricity services. As the energy transition progresses, market efficiency is likely to be increasingly challenged, including due to increased risk and uncertainty. We intend to consider the extent to which reform options identified through the Review will promote productive, allocative and dynamic efficiency in the provision and use of network services.
- **Innovation and flexibility:** As the energy transition progresses, it will be increasingly important for the regulatory framework to support innovation and flexibility. We intend to consider the extent to which the proposed rule changes and reform options identified through the Review will support innovation and provide for the benefits of innovation to be passed through to consumers and be sufficiently flexible to accommodate market, technological, policy, climate and other changes.
- **Principles of good regulatory practice:** Any potential changes to the regulatory framework arising as a result of either the rule change requests, or reform options identified in the Review will need to emulate principles of good regulatory practice. We intend to consider the extent to which reform options identified through the Review will provide for a predictable and stable regulatory framework, promote transparency and simplicity for all stakeholders, support flexibility and resilience in the regulatory framework by employing a principles-based approach, except where prescription is necessary and align with the broader direction of reforms.

29 We are seeking feedback on the proposed assessment criteria.

Submissions are due by 24 September 2026 with other engagement opportunities to follow

30 There are multiple options to provide your feedback throughout the Review processes.

31 Written submissions responding to this consultation paper must be lodged with the Commission by **24 September 2026** via the Commission's website, www.aemc.gov.au.

32 We have included questions in most chapters to guide feedback, and the full list of questions is below. However, you are welcome to provide feedback on any additional matters that may assist the Commission in making recommendations on the Review.

33 We note the large number of questions included in this consultation paper. We encourage stakeholders to only respond to the consultation questions that they have a particular interest in and view on.

34 There are other opportunities for you to engage with us, such as one-on-one discussions, in person public forums and industry briefing sessions. See the section of this paper about "How to engage with us" for further instructions and contact details for the project leader.

Full list of consultation questions

Question 1: Prioritisation framework for the Review

Do you have any feedback on our approach to the Review, including the proposed prioritisation framework?

Note: We consulted on this framework under the Package 1 consultation paper. We will take any *feedback already provided into account for Package 2.*

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?
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.
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.
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.

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.
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?

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?
2. Should changes be made to how consumer preferences are identified, represented and reflected in the revenue determination process?
   a. Is there a need to clarify how consumer views should be used and are there certain topics where consumer views are most relevant?

  b. Could retailers play a more prominent role in representing consumer preferences in the revenue determination process, recognising 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?

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?
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?
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?
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?

Question 6: 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?
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.
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?

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?
2. How could such a mechanism be designed and how could measurement limitations be addressed?
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?

1. What are your views on the effectiveness of the incentive framework for network innovation?

2. What improvements can be made to this framework to drive greater levels of innovation?

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 underway does the framework appropriately allocate risk between NSPs and consumers?
2. Are the various intra period and ex post adjustment mechanisms appropriately targeted and fit for purpose?

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?
2. Are there aspects of the regulatory framework that act as a barrier to efficient anticipatory investment? Please provide evidence or case studies.

Question 11: Does the RoRI enable appropriate compensation for risk within the context of the regulatory package as a whole?

1. Are emerging transition-related risks systematic or business-specific in nature?
2. Are TNSPs and DNSPs facing increasingly different risk profiles and, if so, are those differences relevant for the RoRI?
3. Does the current RoRI framework provide sufficient flexibility to reflect changes in systematic risk over time?

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?

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the recommendations by participating in the Review process. Engaging with stakeholders helps us understand the potential impacts of our recommendations and, in so doing, contributes to well-informed, high quality Review recommendations.

We have included questions in each chapter to guide feedback, and the full list of questions is above. However, you are welcome to provide feedback on any additional matters that may assist the Commission in making its decision.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by 24 September 2026.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code EPR0201.[2]

Tips for making submissions are available on our website.[3]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive, defamatory, vexatious or irrelevant content, or content that is likely to infringe intellectual property rights).[4]

Other opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions, in-person public forums and workshops.

Our first public forum will be held in Sydney on 18 August 2026, with options to attend either in person or online. In person attendance will be subject to venue capacity limits. More details, including how to book, are available on the project page.

If you would like to speak with the project team, please reach out using the details below or use the contact project leader button on the project page.

For more information, you can contact us

Please contact us with questions or feedback at any stage, and note the project code.

Email:	aemc@aemc.gov.au
Telephone:	(02) 8296 7800

2 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

3 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3

4 Further information is available here: https://www.aemc.gov.au/contact-us/lodge-submission

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1 The context for the Electricity Network Regulation Review

We have commenced a review of the regulatory framework for electricity networks to ensure it remains fit for purpose as we transition to net zero. This consultation paper relates to Package 2 of the Electricity Network Regulation Review (ENRR or Review) and should be read in conjunction with the Package 1 consultation paper and final Terms of Reference.

Package 2 of the Review (this paper) focuses on the revenue setting framework for regulated network services, including detailed consideration of:

- how the regulatory determination process operates, including the operation of the propose-respond model
- how incentives are used to align the actions of network service providers (NSPs) with consumers' interest, including consideration of explicit incentive schemes and implicit incentives within the ex ante regulatory framework, and
- risk allocation and compensation under the regulatory framework.

For further details on our approach to the Review see section 1.2 below and the final Terms of Reference.

1.1 Reasons for the Review

1.1.1 Electricity network regulation matters for consumers

Electricity is fundamental to our way of life, and the design choices we make about the electricity system and the network regulatory framework have a direct impact on people's quality of life. These choices impact the reliability of supply, the amount consumers pay for electricity,[5] and have broader environmental impacts. The price of electricity also affects the broader economy and the international competitiveness of our industries.

The way we regulate electricity networks influences these outcomes. Electricity networks are generally considered natural monopolies because a single service provider can provide core network services more efficiently and at a lower cost than multiple competitors. However, being the only supplier of network services in a geographic area means NSPs are not subject to the same constraints they would face in a workably competitive market.

In the absence of competition, regulation seeks to provide incentives to NSPs to deliver the services that customers want at prices that reflect an efficient cost of supply. As a result, monopoly electricity networks operate under a highly regulated framework. They are subject to obligations and controls that, amongst other things, determine the services they can (or must) provide, the costs that can be recovered from electricity consumers, and the risks and rewards that the network businesses face.

The integrity and efficacy of this economic regulatory framework has a strong bearing on overall outcomes for electricity consumers because network costs typically account for between a third and half of customers' final bills.[6]

5 Consumers' bills are determined by charges related to network infrastructure, wholesale cost, retail costs, and government schemes.

6 The network component in the AER's default market offer 7 (2025-26) made up between 33% and 48% of customer prices. Source: AER, *2026-27 Default market offer prices, Final determination*, 26 May 2026.

1.1.2 The energy transition is creating new challenges and the framework must adapt to promote consumer outcomes

The National Electricity Market (NEM) is in the midst of profound change. Both international and domestic factors drive this change and by many measures the NEM is at the forefront of the transition to a renewables-based and decentralised electricity system.[7] The changes underway have substantial implications for the electricity network regulatory framework, which must adapt in order to meet consumers' changing needs and expectations, enable new opportunities and protect from new challenges and risks. The key changes underway and the implications for the network regulatory framework include:

Rapid growth in consumer energy resources (CER)

NEM customers have invested in world-leading levels of CER over the past decade, [8] driven by technological improvements, cost declines, supporting government policies and individual decarbonisation objectives. This includes investment in rooftop PV, behind the meter batteries, vehicle-to-grid enabled electric vehicles and home energy management systems.

The ongoing growth in CER creates opportunities for consumers to benefit, including by NSPs using coordinated CER to avoid or defer network augmentation as well as to provide bulk power supply and system security services. This presents the potential to reduce total system costs and return more value to consumers.

However, for NSPs to realise these opportunities and pass benefits on to consumers, the framework must support cost effective ways to coordinate CER, appropriate compensation and appropriate sharing of risks. The regulatory framework needs to ensure that Distribution Network Service Providers (DNSPs) interests and incentives with regard to CER align with consumers' interests, as DNSPs take on a formal role as the distribution system operator (DSO).

Increasing wind, solar and storage at grid scale

Cost declines and government policies have led to rapid growth in wind and solar generation and battery storage at the transmission level. Generation from renewable sources supplied over 50 per cent of electricity in the NEM at the end of 2025, up from around 10 per cent just 15 years ago.[9]

New renewable generation is often located in different parts of the electricity system than the thermal generation it replaces, creating a need for major new transmission investment.[10] These new developments often require 'greenfield' development through areas that have not previously hosted network infrastructure. The development of such projects poses distinct challenges and risks compared to augmentation or brownfield development, raising questions about how these risks should best be allocated and compensated for.

The increasing cost competitiveness of batteries and other forms of energy storage also enables greater potential to deploy non-network options as a way of deferring or avoiding network

7 Australia has the highest per capita capacity of utility-scale battery capacity and generation from renewable sources supplied over 50 per cent of electricity in the NEM at the end of 2025. Source: Clean Energy Council, *Clean Energy Australia 2026*, May 2026; AEMO, *Quarterly Energy Dynamics Q4 2025*, January 2026.

8 Around 40 per cent of households have rooftop solar PV, the highest rate in the world. Source: Clean Energy Council, *Clean Energy Australia 2026*, May 2026; IEA, *Snapshot of Global PV Markets 2026*, April 2026.

9 AEMO, *Quarterly energy dynamics, Q4 2025*, January 2026; AER, *State of the energy market*, 2011, p. 27.

10 AEMO estimates around 6,000 km of new transmission will need to be constructed by 2050 to deliver the least cost system that is consistent with emissions reduction targets set by jurisdictions. Source: AEMO, *2026 Integrated System Plan*, June 2026.

augmentation. These solutions can in some contexts be deployed at lower cost and can increase optionality by deferring major capital investment decisions, to the benefit of consumers.[11]

Rapid but uncertain demand growth

Electricity demand is forecast to grow, but the pace of growth is subject to substantial uncertainty. Key drivers of demand growth include fuel switching at the residential and industrial level, the electrification of transport, and the connection of major new loads such as data centres. However, this growth is highly dependent on factors that are difficult to predict in advance, including international trends in technology costs, government support policies across multiple sectors of the economy and Australia's relative attractiveness for globally competitive industries.

The ex ante, incentive based framework for electricity networks is premised largely on the ability to accurately forecast NSPs' expenditure requirements over a forward period, which are influenced by the forecast level of demand. Greater levels of uncertainty raise questions about the allocation of risks between consumers and NSPs, the appropriate use of intra-period adjustment mechanisms, and the effectiveness of incentive mechanisms set with reference to ex ante forecasts.

Demand growth also increases the scale and pace of network investment, relative to recent decades. This raises questions about whether the current incentive framework sufficiently enables the scale and pace of investment required, or places too much emphasis on short-term cost reduction at the potential expense of more efficient long-term outcomes.

Broader cost of living pressures for consumers

These changes to the NEM are taking place against a backdrop of cost of living pressure for consumers, who have recently experienced energy price increases. Forecast demand growth is likely to necessitate an increased investment in network infrastructure, but also creates the opportunity to increase network utilisation and potentially reduce per-unit costs for consumers. Technological development is enabling new ways of meeting network needs and new regulatory approaches, all of which could benefit consumers. . Ensuring these opportunities for consumers are realised, and that consumers pay no more than necessary, are of paramount importance to maintaining social licence for the energy transition.

1.2 Our approach to the Electricity Network Regulation Review

The Commission is initiating the Review under section 45 of the National Electricity Law (NEL).[12] There is a broad range of topics that could potentially be considered by this Review. We will focus on areas where our recommendations are most likely to deliver the greatest improvement in consumer outcomes, prioritising those issues that are not being examined (or have not been recently examined) through other processes.

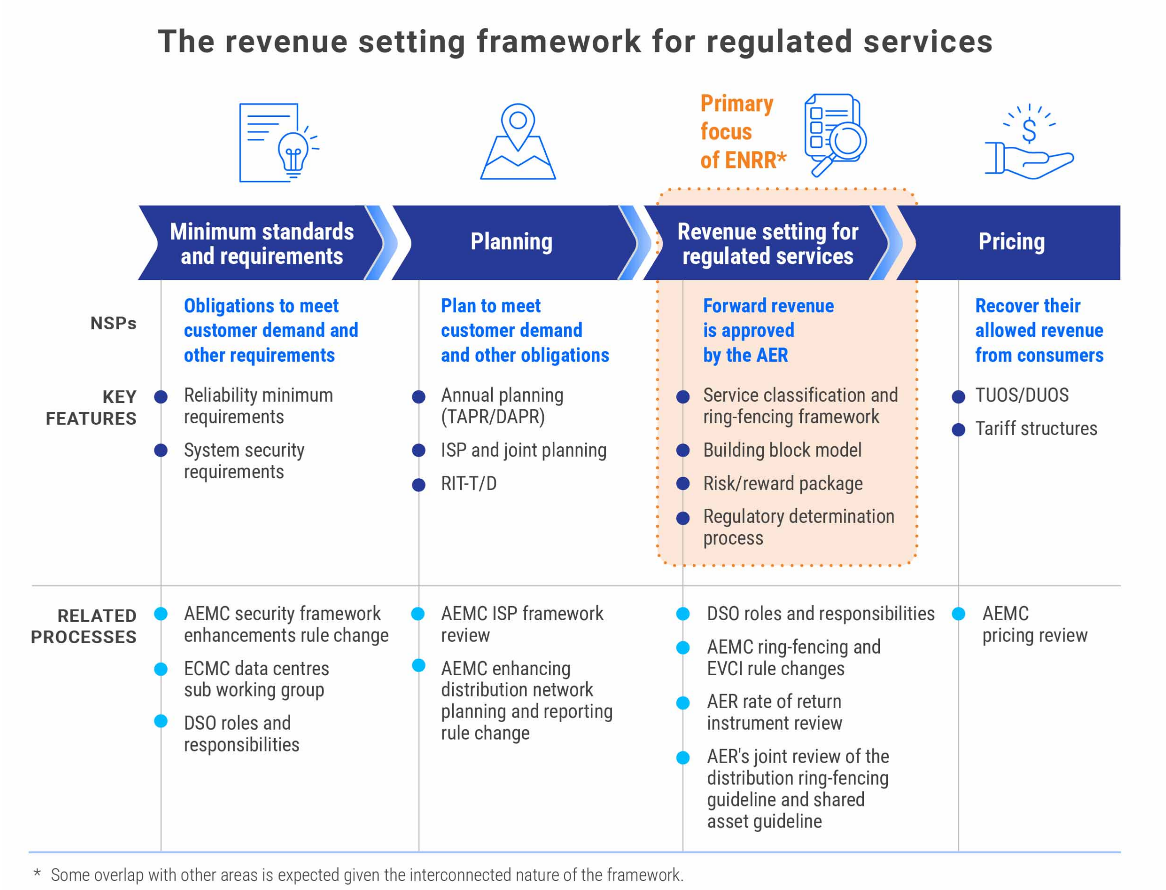
Our Review will focus on the aspects of the framework that determine how an NSP's revenue required for the provision of regulated services is set.[13]

11 Transgrid's Bathurst, Orange and Parkes Supply RIT-T identified a non-network option (battery energy storage system and other technologies) as the preferred option, which enabled deferral of a network investment. The estimated net benefits of the preferred (non-network) option were around $2.55 billion higher than the highest ranked network option. Source: Transgrid, *Maintaining reliable supply to the Bathurst, Orange and Parkes areas, RIT-T Project Assessment Conclusions Report*, June 2022.

12 Part 4 of the NEL sets out the functions and powers of the AEMC. Under Division 5 of Part 4, the AEMC has the power to conduct a review into the operation and effectiveness of the National Electricity Rules (NER).

13 Regulated services are referred to as 'direct control services' for distribution (divided into 'standard control' and 'alternative control' services) and 'prescribed transmission services' for transmission under the National Electricity Rules.

Figure 1.1: The Review will focus on the revenue setting framework for regulated services



Source: AEMC.

We are focusing on the revenue setting framework for regulated services for two primary reasons:

- **The energy transition has changed consumer expectations and behaviour and as such the role of networks.** The energy transition is impacting a number of the fundamental principles underpinning the existing economic regulatory framework, including the role of NSPs in contestable markets, the viability of non-network options, and the ability to make robust forecasts and estimates over the medium term. Many aspects of the framework are interconnected, making them challenging to consider in isolation. It has also been several years since a comprehensive review of the economic regulatory framework for NSPs was undertaken.[14]
- **Other areas have been examined through recent or ongoing work programs, or can be considered independently**. Market bodies or governments have undertaken substantive work programs to improve the regulatory arrangements for system security, network planning and network pricing in recent years. Other issues may be separable, meaning they are largely discrete and may be more effectively addressed through separate processes. This Review will focus on areas that form a core part of the economic regulatory framework, while acknowledging that some overlap with other areas may be unavoidable, given the

14 The last comprehensive review of the economic regulatory framework was undertaken by the AEMC in 2020. AEMC, *Final Report: Electricity Network Economic Regulatory Framework 2020 Review*, 1 October 2020.

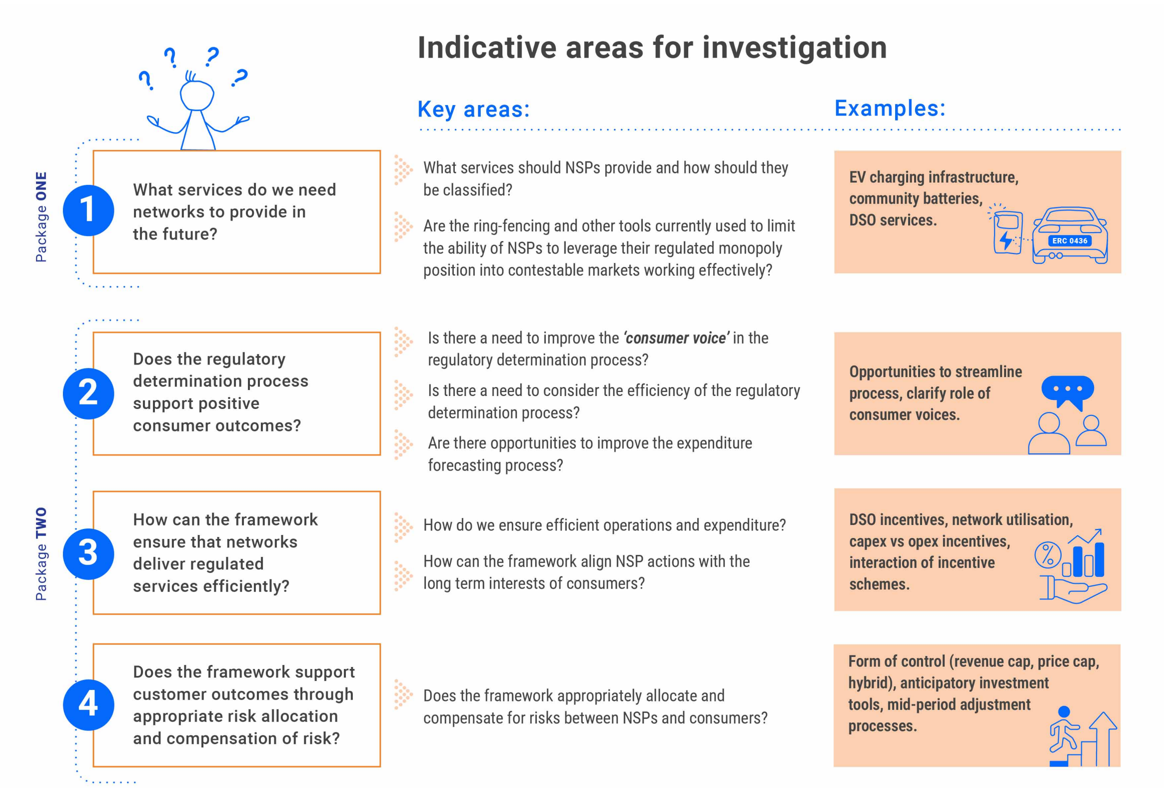
interconnected nature of the regulatory framework for NSPs more broadly (as illustrated in Figure 1.1 above).

Our Review will focus on four central policy areas that matter for consumers:

1. What services do we need networks to provide in the future? (focus of package 1, see section 1.2.1 for more context)
2. Does the regulatory determination process support positive consumer outcomes? **(focus of this consultation paper)**
3. How can the framework ensure that networks deliver regulated services efficiently? **(focus of this consultation paper)**
4. Does the framework support consumer outcomes through appropriate risk allocation and compensation of risk? **(focus of this consultation paper)**

We consider that these areas capture the majority of issues raised by stakeholders in our scoping work for this Review. Figure 1.2 below shows indicative questions and issues for further investigation under each of the four primary areas.

Figure 1.2: The questions we will explore in the Review



Source: AEMC.

1.2.1 We are progressing the Review across two separate packages

We have split the Review in two 'packages':

- **Package 1** will cover policy area 1 in Figure 1.2. It will focus on how different services provided by NSPs are classified and regulated, and the tools currently used to limit the ability of NSPs to leverage their regulated monopoly position into contestable markets. This includes ring-fencing, cost allocation, connections and facility access and shared asset arrangements. We refer to this aspect of the regulatory framework collectively as the service classification and ring-fencing framework.

- **Package 2 (this paper)** will cover policy areas 2-4 in Figure 1.2. It will examine whether the regulatory determination processes supports positive consumer outcomes, whether the framework could better support efficient service delivery, and whether it provides for an appropriate risk allocation and compensation mechanisms. It will run until the end of 2027 with multiple rounds of formal consultation along the way before making final recommendations.

We have initiated Package 1 alongside the two related rule changes from Nexa and ENA, which focus on ring-fencing and EVCI, respectively. We are also progressing another EVCI rule change request from the Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW) through a separate process that will run in parallel to the Electricity Network Regulation Review and Nexa and ENA rule changes.

1.2.2 We will further refine the focus of the Review in consultation with stakeholders

Given the potentially large number of issues that the Review could consider and the need to ensure timely reform of the economic regulatory framework in response to the energy transition, we consider that the scope of the Review will need to be further refined as we progress to maximise reform impact. Focussing on the material issues with the framework will enable us to identify tangible reforms that can be implemented promptly to improve consumer outcomes.

We have developed a policy prioritisation framework to help us transparently determine the priority of issues for further consideration under this Review.

The proposed criteria are set out in the table below and have been developed to ensure the Review focuses on issues that:

1. will make a difference to consumer outcomes **(materiality)**
2. are practically implementable, focusing on issues with high implementation prospects **(implementation feasibility)**
3. are not already being addressed by another process, or have not recently been considered by the AEMC or another body **(other process)**, and
4. are not easily separable for discrete consideration through a stand-alone process, given the integrated nature of the economic regulatory framework **(separability)**.

Table 1.1: Prioritisation framework

Criteria	Matters we will consider
Materiality of the issue	How significant is the issue and how strong is the evidence base? How much do consumers stand to benefit from addressing the issue?
Implementation feasibility	Are other practical solutions available? Can solutions be implemented by the AEMC through NER changes, or do they require agreement and coordination from other actors (e.g. Energy Ministers)? If coordination is required, how difficult will it be?
Other process	Is there another rule change process already underway, or are there formal review processes

Criteria	Matters we will consider
	already established (or have recently been concluded), that are better placed to review this aspect of the framework and efficiently address the identified issue?
Separability of the issue	Is this an issue that is difficult to consider in isolation? Or can it be separated and progressed through a stand-alone process that would likely lead to faster resolution of the issue (e.g. a rule change or other process)?

We have used this framework to identify the priority issues to be considered in this Package 2 consultation paper (see appendix A for a summary of our assessment). We intend to apply the same framework when considering whether to include any additional issues identified by stakeholders through the consultation process.

Question 1: Prioritisation framework for the Review

Do you have any feedback on our approach to the Review, including the proposed prioritisation framework?

Note: We consulted on this framework under the Package 1 consultation paper. We will take any feedback already provided into account for Package 2.

1.2.3 The NEO will guide our Review

The Review will consider potential reforms to the economic regulatory framework that applies to both TNSPs and DNSPs in the NEL and the NER. Our work on the Review will therefore be guided by the national electricity objective (NEO), which is:[15]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gasemissions.

Our Review will also be guided by:

- the **form of regulation factors** in section 2F of the NEL,[16] when we are considering how network services should be regulated (see section 5.2 for an overview of the form of regulation factors)

15 Section 7 of the NEL. Under section 32 of the NEL, the AEMC must have regard to the NEO in performing or exercising any function or power under the NEL.

16 Section 88A of the NEL.

- the **revenue and pricing principles** in section 7A of the NEL,[17] when we are considering reform options relating to the arrangements for revenue and price setting related to the provision of services that are the subject to economic regulation (see section 5.2 for an overview of the revenue and pricing principles).

Considering the NEO and the issues that are likely to arise under each of the policy areas outlined above, we propose to use the following assessment criteria when considering any potential reforms to the regulatory framework:

- Outcomes for consumers
- Emissions reduction
- Principles of market efficiency
- Innovation and flexibility
- Principles of good regulatory practice.

These criteria reflect the key potential impacts – costs and benefits – of potential reforms to the regulatory framework, which we will consider within the broader framework of the NEO. Chapter 5 provides further detail on our rationale for selecting these criteria. See the Final Terms of Reference for further information on our approach to the Review, including further details on stakeholder consultation.

1.3 This Review fits within the broader reform landscape

Other reform processes that will start soon, are underway, or have recently been completed, have implications for this Review. Key processes include:

- **Expected rule change on DSO roles and responsibilities**: We are expecting a rule change request to embed DSO expectations, rights and obligations in the NER. This follows a decision by Energy Ministers in December 2025 to formalise DNSPs as the DSOs in the NEM.[18]
- **The pricing review: Electricity pricing for a consumer driven future**: The AEMC has recently completed its self-initiated review of electricity retail and network pricing - the Pricing Review. The Pricing Review examined how markets and regulatory frameworks can provide the products and services that best match consumer preferences, now and into the future. A key area of focus for the Pricing Review has been the role of distribution networks and network tariffs in enabling the right products and services for consumers and driving efficient network investment and utilisation. The AEMC issued its final report for the Pricing Review on 18 June 2026.[19]
- **Data centres**: The AEMC provided advice to energy Ministers on how data centres can be required to bring their own generation, operate flexibly and connect efficiently to the grid, to ensure electricity consumers are not worse off. The advice was considered at the July 2026 ECMC.[20] Jurisdictions are now collaborating to develop requirements for data centres to source clean energy, including by surrendering Renewable Electricity Guarantee of Origin (REGO) certificates from new generators to offset the power they use. In addition, they are developing a rule change proposal to give effect to the AEMC advice. Including proposals to:
    - require data centres to demonstrate that their demand is backed by new firm capacity

17 Section 88B of the NEL.

18 CER Taskforce, *Redefining roles and responsibilities for power system and market operations in a high CER future*, December 2025. Energy Ministers, *Meeting Communique*, December 2025.

19 AEMC, *The pricing review - Electricity pricing for a consumer-driven future, Final report,*June 2026.

20 Energy Ministers, *Meeting Communique*, July 2026.

- amend the connections process to encourage data centres to shift demand and co-locate with generation, easing pressure on the network.

The AEMC will also shortly initiate rule change proposals regarding data centres already submitted. This includes one from AEMO that proposes improving operational visibility and integration of data centres, including consideration of treating data centres as market participants. The others are rule change proposals from Minister Bowen that seek to close the gaps in how data centres pay for the network upgrades triggered by their connections. The AEMC will also finalise its updates to technical standards for large inverter-based loads, like data centres, in late October 2026.

- **Integrated System Plan review**: The AEMC is currently undertaking a review of the Integrated System Plan (ISP) framework. We are required by the NER to complete the ISP Review by 1 July 2027. The ISP review is considering a range of matters including the objectives of the ISP and its evolution over time to meet power system needs, its relationship with the economic assessment of transmission projects, as well as the process for developing and consulting on the ISP.

1.4 Package 2 will consider the revenue setting framework for regulated services

1.4.1 Our starting point is to consider reform within the ex ante, incentive based framework

The regulatory framework that applies to NSPs in the NEM is described an ex ante, incentive based approach. Under this approach, an NSPs' regulated revenue is determined ahead of time (ex ante), with incentives to outperform their allowances to generate efficiencies, and as such benefits for consumers. An ex ante, incentive based approach contrasts with a cost of service approach to network regulation used in some international jurisdictions where actual costs are assessed in greater detail after they have been incurred (ie ex post). In practice the NEM framework also includes some ex post elements as well.

The starting point for this Review is to consider changes within the ex ante, incentive based framework. This is consistent with our intent signalled in our Draft Terms of Reference.[21] We do not consider there is a compelling case for moving away from an ex ante, incentive based framework at this point in time for a number of reasons:

- The current framework has maintained or improved the efficiency of many categories of network expenditure over time (a brief discussion of the performance of the ex ante incentive framework to date is discussed further in chapter 3). Consumers benefit from the repeat nature of the revenue determination process, which reveals information to the regulator and allows the sophistication of regulatory tools to mature over time. This paper explores potential issues with the framework and areas for possible improvement, but we do not consider there is a compelling case for a fundamental reset at this point.
- The Commission is not aware of examples of other electricity regulatory regimes moving away from an ex ante based approach – rather, jurisdictions with a cost of service (ex post) framework are increasingly introducing incentive mechanisms to encourage cost efficiencies.[22]
- Starting with a blank slate would substantially increase implementation timeframes and complexity of the Review. It would likely require fundamental changes to the National

21 AEMC, *Electricity network regulation review, Draft terms of reference*, December 2025.

22 For example the Earning Adjustment Mechanisms introduced in New York and reliability, resilience and customer service performance incentive mechanisms introduced in Illinois.

Electricity Law, require coordination of many more entities and have lengthy and complex implementation considerations. However, this does not mean that the Review will not consider fundamental changes to the regulatory framework within the bounds of the ex ante, incentive based framework.

- The framework is not binary – the current framework already contains ex post elements and there is scope to consider these further where necessary.

As indicated above, we emphasise that this starting point does not rule out ambitious and substantive reform. Nor does this starting point imply that we consider the framework is entirely fit for purpose in its current form going forward. We will consider the need for reform where a strong evidence base indicates that consumers stand to benefit from a change in the regulatory framework.

1.4.2 Package 2 covers three focus areas which are interconnected and together determine NSPs' revenue for regulated services

At its most basic, the existing ex ante, incentive based framework requires the regulator to determine the revenue allowance that a prudent and efficient NSP would require to provide regulated services over the forthcomming regulatory period. Determining the revenue allowance before the commencement of the regulatory period and before costs are incurred can provide NSPs a strong incentive to pursue cost efficiencies. This is because they can retain some of the difference between the revenue allowance and the actual costs incurred within the regulatory period, and must also bear some of the cost of any overspend within the period. The revenue allowance is determined using the building block approach and administered through a propose-respond regulatory determination process. **The revenue determination process is the focus of chapter 2**.

While the ex ante approach can encourage NSPs to seek out cost efficiencies, this overall framework can create other unintended incentives. For example NSPs may be financially rewarded for pursuing efficiency gains by reducing service quality, below the level that consumers value and would otherwise be willing to pay for. NSPs may also face declining incentives to make cost savings over the regulatory period. A number of formal incentive schemes have been introduced over time to counterbalance and correct for some of these incentives. **The incentive framework is the focus of chapter 3.**

The ex ante approach can also expose NSPs to a number of risks, including demand, expenditure and regulatory risks, many of which are outside an NSPs' control. These risks may affect an NSP's ability to efficiently invest in infrastructure and provide the network services that consumers require. The allocation of systematic risk also determines that appropriate rate of return for the provision of network services. Other project- or business-specific risks are more within an NSP's control and it may be appropriate that NSPs bear these risks. The regulatory framework allocates these risks through a number of intra-period adjustment mechanisms. **These risk allocation and compensation mechanisms are the focus of chapter 4.**

In practice these three areas are interconnected. The allocation of risk has a bearing on incentives (and vice versa) and the revenue determination process creates incentives and determines risk allocation and compensation. While we acknowledge these connections, we have broken the framework down into these component parts with the intent of clarifying the objectives of different parts of the framework and facilitating a structured process to identify and agree issues for further exploration.

2 Efficient revenue determination processes that promote consumers' long term interests

The revenue determination process is a key element of the ex ante incentive based regulatory framework that applies to both TNSPs and DNSPs in the NEM.

A key question for Package 2 of the Review is whether the current revenue determination process is supporting outcomes in the long term interest of consumers, or if changes may be required. This chapter sets out:

- a brief overview of the overarching objectives of the revenue determination process (section 2.1)
- how the current revenue determination process works (section 2.2).
- areas we propose to explore further, including whether changes could:
  - improve the efficiency of the process (section 2.3)
  - support better quality regulatory proposals and regulatory decisions (section 2.4)
  - ensure that electricity consumers' interests are appropriately represented and reflected in regulatory proposals and revenue determinations (section 2.5).

2.1 Objective of the revenue determination process

Electricity networks are generally considered natural monopolies because a single service provider can provide core services more efficiently and at a lower cost than multiple competitors. While a natural monopoly may be efficient, it can mean NSPs are not subject to the same discipline they would face if they operated in a competitive market. This is why most of the services that NSPs provide, including the transmission and distribution of electricity, are subject to direct economic regulation by the AER.

The NER economic regulatory framework applying to transmission and distribution networks is based on an ex ante incentive based approach, which seeks to promote the long term interests of electricity consumers. Under this framework, the AER determines the revenue that an NSP is allowed to recover from its customers in the forthcoming regulatory control period. Setting the regulatory allowance for an NSP occurs through the multi-stage propose-respond-based revenue determination process set out in the NER.

The **primary objective** of this process is to enable the AER to determine the revenue a prudent NSP would require in the forthcoming period to efficiently invest in, operate and maintain the network and provide regulated services in a manner that promotes electricity consumers' long term interests. This, in turn, requires the AER and the NSP to have a good understanding of both:

- the **efficient costs of providing the regulated services**, including (but not limited to) the capital and operating expenditure required to meet projected demand, maintain service and/or network safety, quality, reliability and security, comply with regulatory obligations and contribute to achieving emissions reductions targets, and
- **electricity consumers' preferences and their long term interests** in relation to price, service and/or network safety, quality, reliability, safety and security and emissions reduction.

The revenue determination process, as set out in further detail in the next section, seeks to support:

- the identification of both the efficient costs of providing regulated services and consumers' preferences, and

- robust and transparent regulatory decision making, minimising regulatory burden and regulatory costs that are ultimately borne by electricity consumers.

2.2 Overview of the revenue determination process

2.2.1 The AER must determine an NSP's revenue allowance on an ex ante basis in accordance with the NER

The AER is required to use the building block approach and consider a number of other matters

When determining an NSP's revenue allowance, the AER is required to apply the building block approach.[23] It must also comply with a number of other requirements set out in the NEL, NER[24] and subordinate regulatory instruments when applying the building block approach, including:

- the Rate of Return Instrument (RoRI) that the AER is required by the NEL to develop every four years, which is binding on the AER and NSPs in the revenue determination process,[25] and
- a number of regulatory models,[26] guidelines[27] and incentive schemes[28] that the AER is required to develop outside the revenue determination process.

The NEL requires the AER to perform this economic regulatory function in a manner that will, or is likely to contribute to the long-term interests of consumers. The AER is also required to take into account the revenue and pricing principles (RPPs) when exercising any discretion in making its determination (see chapter 5).[29]

The AER uses the building block approach to determine the costs a prudent and efficient NSP would incur providing regulated services

The building block approach involves summing the forecast costs (building blocks) that a prudent service provider would incur efficiently investing in, operating and maintaining the network and providing regulated services in the forthcoming regulatory period. This includes a rate of return that reflects the risks involved in providing these services.

The key building blocks, which are set out in Figure 2.1, include the return on capital, depreciation, operating expenditure (opex), tax and incentive schemes.

23 NER, cl. 6.3, 6.8.2(c)(2) and 6.12.1(b) and cl. 6A.5.4 and 6A.4.2.

24 This includes the rules in Chapters 6 and 6A of the NER, as well as rules in Chapter 8A (participant derogations), Chapter 9 (jurisdictional derogations) and Chapter 11 (savings and transitional rules) of the NER.

25 NER, cl. 6.5.2 and cl. 6A.6.2.

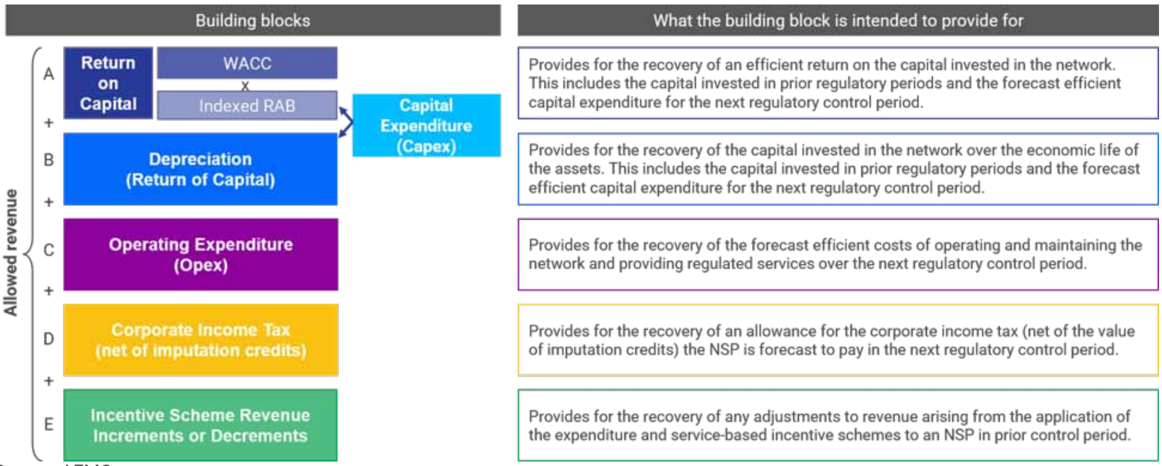
26 These include the AER's post-tax revenue model and roll forward model.

27 These include, amongst others, the AER's *Electricity Distribution Service Classification Guideline*, August 2022, *Distribution Reliability Measures Guideline*, December 2024, *Restricted Asset Exemption Guideline*, September 2018, *Cost Allocation Guidelines*, June 2008, *Shared Asset Guidelines*, June 2025, *Capital Expenditure Incentive Guidelines*, August 2025, *Expenditure Forecast Assessment Guidelines*, October 2024, *Network Alternative Support Payment Guidelines*, March 2026, *System Security Network Support Payment Guideline*, November 2024, *Financeability Guideline*, November 2024, *Confidentiality Guideline*, August 2017 .

28 These include the AER's Efficiency Benefits Sharing Scheme, the Capital Expenditure Sharing Scheme, the Service Target Performance Incentive Scheme, the Demand Management Incentive Scheme and Small Scale Incentive Scheme (SSIS).

29 Section 16 of the NEL.

Figure 2.1: Building block approach used to calculate an NSP's ex ante revenue allowance



Source: AEMC.

Note: The rules applying to the calculation of the allowed revenue for TNSPs and DNSPs are largely the same, with the following exceptions. Chapter 6A allows a TNSP's revenue allowance to include compensation for risks the AER determines is necessary because the risks are not otherwise compensated in the return on capital. Chapter 6A also allows a TNSP's revenue allowance to include financeability adjustments.

The NER set out the specific matters that the AER must consider when assessing an NSP's proposal in relation to each of the building blocks in Figure 2.1. In the case of forecast opex and capital expenditure (capex), which can have a material bearing on the revenue that NSPs can recover in the regulatory control period and into the future, the rules also allow the AER to:[30]

- closely scrutinise an NSP's expenditure forecast, including by having regard to the results of its most recent benchmarking report, and
- replace the NSP's forecast with its own forecasts, if it would better reflect the expenditure criteria in the rules.

To help inform its assessment of whether to accept an NSP's opex and capex forecasts and to overcome some of the information asymmetries it faces, the AER currently uses a combination of top-down and bottom-up expenditure forecasting methods, which in the case of:[31]

- Opex, involves the use of both:
  - a base-step-trend approach, with an NSP's revealed expenditure forming the 'base' for the forecast of future expenditure, with adjustments made for a 'step' change in costs not otherwise reflected in the revealed expenditure and for 'trend' changes in input costs, output growth and productivity,[32] and
  - other techniques are used for specific categories of opex.
- Capex, involves the use of both:
  - top-down modelling (e.g. benchmarking and category analysis) to test the total capex and category level forecasts, and
  - bottom-up modelling (e.g. predictive modelling, trend analysis, cost benefit analyses and engineering review) for particular capex projects.

30 NER, cl. 6.5.6-6.5.7 and cl. 6A.6.6-6A.6.7.

31 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, Chapter 3 and AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, October 2024, Chapters 3-4.

32 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024.

2.2.2 The rules currently provide for a multi-stage revenue determination process that is based on the propose-respond model

The revenue determination process in the NER is based on the propose-respond model, which at a high level requires:

- NSPs to submit their regulatory proposal to the AER for the forthcoming regulatory control period, and
- the AER to assess the regulatory proposal and determine whether or not to approve it, having regard to relevant provisions in the NEL, NER and other subordinate regulatory instruments.

Figure 2.2 provides an overview of the key stages in the revenue determination process. There are currently three distinct stages: the Framework and Approach (F&A) stage, NSP regulatory proposal development stage and AER regulatory determination stage.

The AER can use the **F&A stage** to provide NSPs with guidance on its proposed position on the following matters before an NSP submits its regulatory proposal:

- **DNSPs**:[33] Service classification,[34] form(s) of control mechanism(s) and the formulae that give effect to the control mechanisms,[35] treatment of dual function assets, incentive schemes, if depreciation is to be based on forecast or actual capex and application of the AER's *Expenditure forecast assessment guidelines*.[36]
- **TNSPs**:[37] Incentive schemes, if depreciation is to be based on forecast or actual capex and the application of the AER's *Expenditure forecast assessment guideline*.[38]

This stage of the process also provides for NSPs to advise the AER of the approach to expenditure forecasting it intends to use in its regulatory proposal.[39] This step was added through the 2012 *Economic regulation of network service providers* rule change to help facilitate early engagement between the AER and NSPs on expenditure forecasting and the models NSPs intend to use and to save time and effort once the regulatory process commences.[40]

Importantly, most of the positions identified through the F&A stage are not binding on the NSP or the AER in the revenue determination process. The only exceptions to this are the DNSP service classification and form of control mechanism and formulae positions, with the NER only allowing the AER to depart from:[41]

- the service classification and form of control formulae set out in the F&A paper if it considers that a material change in circumstances justifies the departure, and
- the form of control mechanism set out in the F&A paper if it has departed from the classification of a service and considers that no form of control mechanism set out in that paper should apply to that distribution service.

33 NER, clauses 6.8.1.

34 The classification used in a distribution determination must be the same as that set out in the relevant F&A paper, unless the AER considers that a material change in circumstances justify departing from the classification. See NER, cl. 6.12.3.

35 The form of control mechanism used in a distribution determination must be as set out in the relevant F&A paper unless the AER has departed from the classification and considers that no form of control mechanism should apply. The formulae must also be the same as that set out in the F&A paper unless the AER considers that a material change in circumstances justifies departing from the formulae in the F&A paper. See NER, cl. 6.12.3.

36 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024.

37 NER, clauses 6A.10.1A.

38 AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, October 2024.

39 NER, clauses 6.8.1A and 6A.10.1B.

40 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p. 110.

41 NER, clause 6.12.3.

At the time the F&A stage was implemented in the NER in 2012, the Commission noted the intent for the F&A stage to be an optional stage and only triggered if changes to an existing F&A paper were required.[42] However, in practice, the F&A stage has been triggered in every determination process since.

The **NSP regulatory proposal development stage** occurs in parallel to the F&A stage. This stage of the process is largely a matter for the NSP, although the NER specifies:

- when the NSP must submit its regulatory proposal to the AER (i.e. 17 months before the commencement of the next regulatory control period)[43]
- the information that NSPs must provide with their regulatory proposal[44] and a requirement to comply with any regulatory information instrument issued by the AER,[45] and
- that a regulatory proposal must be accompanied by a plain language overview paper to help support consumer engagement in the revenue determination process and to also explain how the NSP engaged with consumers and other stakeholders when developing its proposal.[46]

The **AER regulatory determination stage** commences once the NSP submits its regulatory proposal. This stage involves a three-step process, with the AER required to:[47]

- publish an issues paper and conduct a public forum shortly after it receives the NSP's regulatory proposal to help support consumer engagement
- consider the NSP's regulatory proposal and stakeholder submissions on the regulatory proposal before publishing a draft determination, which it must then publicly consult on for at least 45 business days, and
- consider the NSP's revised regulatory proposal and submissions on the draft determination before publishing a final determination.[48]

Subject to any intra-period cost pass through, contingent project and/or capex re-opener determinations (see Chapter 4), the AER's final determination on an NSP's revenue allowance is binding for the regulatory control period.

42 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Determination*, November 2012, pp. 29 and 150.

43 NER, clauses 6.8.2 and 6A.10.1.

44 NER, clauses 6.8.2(d) and 6A.10.1.

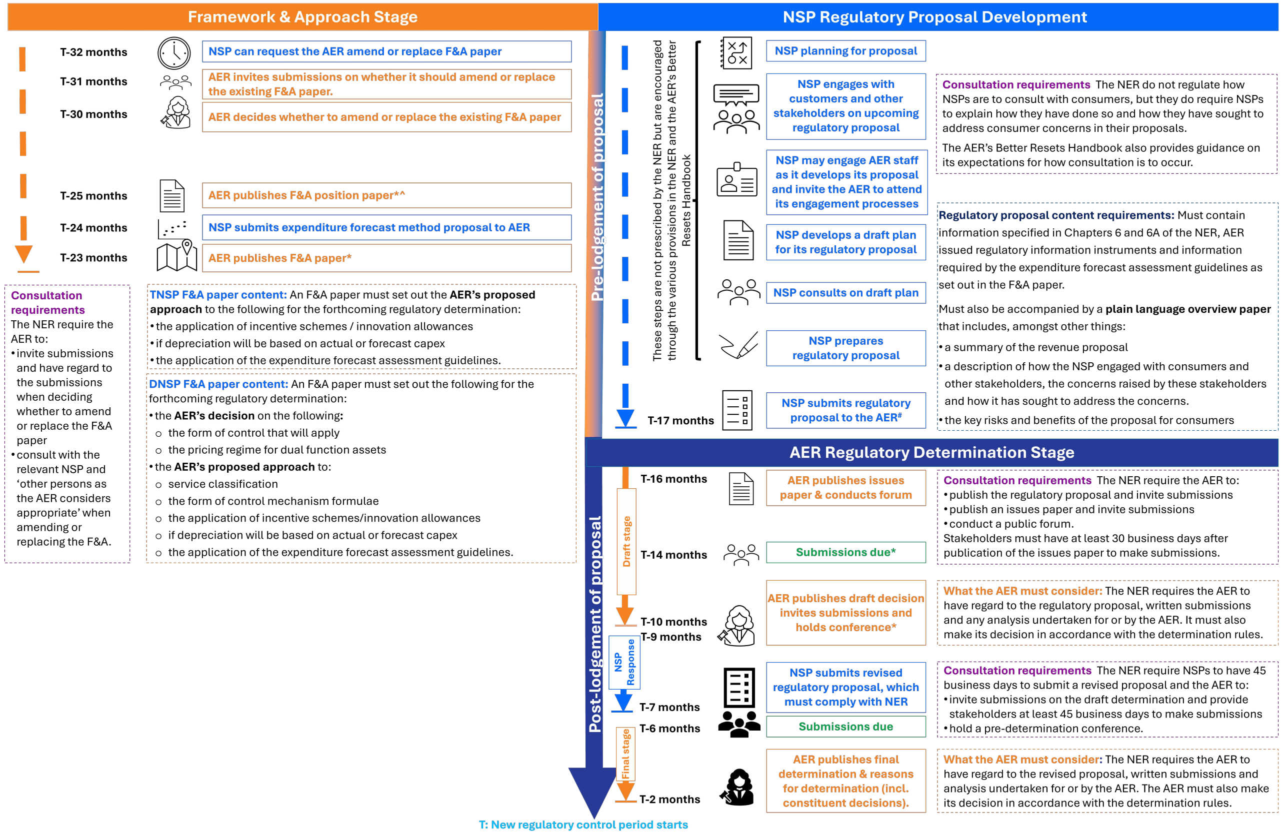
45 NER, clauses 6.8.2(c) and 6A.10.1(f).

46 NER, clause 6.8.2(c1) and clause 6A.10.1(g).

47 NER, clauses 6.10.2, 6.10.3, 6.11.1, 6.12, 6A.12.1 and 6A.12.2, 6A.12.3, 6A.14.1.

48 In Chapter 6A of the NER, this is referred to as a decision rather than a determination.

Figure 2.2: Revenue determination process



Source: AEMC

Note: * The NER does not specify dates for these events. The dates in this figure are instead based on the indicative dates in the AER's regulatory determination timetable. See here.

Note: ^ The AER only has to publish these if it has decided to amend or replace an F&A paper. Note that the rules do not require the AER to publish a F&A position paper, but it is common practice for the AER to do so.

Note: # The NER allows the AER to undertake preliminary examination of a regulatory proposal and accompanying information and if it finds it does not comply with a requirement in the NEL or NER, it may notify the NSP it must be resubmitted.

2.2.3 Consumer engagement to understand consumer preferences are a key input into the revenue determination process

The revenue determination process is intended to result in revenue allowances that enable the NSP to efficiently invest in, operate and maintain the network and provide regulated services in a manner that reflects electricity consumers' long term interests, with outcomes aligned with what consumers value.

Determining what electricity consumers value requires having a good understanding of their preferences, how those preferences differ across different consumer groups and how they may be changing over time (e.g. in response to the growth in CER). This underscores the importance of having broad consumer representation and effective consumer engagement through the revenue determination process.

In 2012, the Commission made changes to the NER to encourage greater consumer engagement in the revenue determination process. These changes were made in response to the AER's concerns about stakeholders' ability to engage effectively in regulatory determination processes.[49] At the time, the Commission noted using the NER to 'force' effective engagement was unlikely to be successful and that a 'cultural shift' was required, which could only come from the parties themselves.[50] The Commission therefore encouraged the AER, NSPs and consumers to take additional steps to improve this engagement.[51]

Consumer engagement requirements in the NER

The NER currently provide for consumer engagement to occur in each stage of the process. To help facilitate this, the rules include a number of provisions that are intended to:

- *Encourage NSPs to engage with customers when developing their proposals by requiring:*
    - NSPs to describe how they engaged with consumers during the development of their regulatory proposal and how they sought to address any consumer concerns,[52] and
    - the AER to consider the extent to which the NSP's expenditure forecasts include expenditure to address customer concerns identified through the engagement process.[53]
- *Help consumers engage more effectively in a revenue determination process by requiring:*
    - NSPs to prepare a plain language consumer focused overview of their proposal,[54] and
    - the AER to publish an issues paper and convene a public forum once the regulatory proposal is submitted and conduct a pre-determination conference once the draft determination is made.[55]

The Commission explained that the inclusion of an expenditure factor relating to consumer views was intended to allow the AER to have regard to the extent to which NSPs had considered what consumers seek when preparing their regulatory proposals. The Commission noted that what

49 AEMC, Directions Paper – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, pp. vi; AEMC, *Economic regulation of network service providers, Final determination*, November 2012.

50 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final determination,* November 2012, pp. 29 and 36.

51 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final determination,* November 2012, pp. 29 and 36.

52 NER, clauses 6.8.2(c1) and 6A.10.1(g).

53 NER, clauses 6.5.6-7 and 6A.6.6-7.

54 NER, clauses 6.8.2(c1) and 6A.10.1(g).

55 NER, clauses 6.9.3, 6.10.2, 6A.11.3 and 6A.12.2.

consumers want and are prepared to pay for may assist in showing what expenditure is efficient.[56] It also noted that, where an NSP has engaged with consumers and taken into account what they seek, the NSP could reasonably expect the AER to take a more favourable view of its proposal.[57]

Additional steps taken outside the rules to improve NSPs engagement with consumers

Following the 2012 changes to the NER, NSPs have taken steps to improve the quality of their consumer engagement and undertaken more extensive engagement to support the development of their regulatory proposals. This has included carrying out customer and stakeholder forums, workshops, surveys and interviews. It has also involved establishing online engagement portals, focus groups, customer panels and advisory/reference groups.

The improvements in this area reflect not only the efforts of NSPs, but also the steps the AER has taken to encourage NSPs to more effectively engage with consumers through a combination of reputational, process and financial incentives. Some of the more notable steps the AER has taken over this period to try and incentivise better engagement include:

- establishing the Consumer Challenge Panel (CCP)[58] and reporting on the quality of NSP consumer engagement in each determination, both of which target reputational incentives
- developing customer service incentive scheme (discussed further in section 3.2.6) to provide NSPs with financial incentives to work with customers to identify service improvements those customers value
- publishing the Better Resets Handbook[59], which provides the following process incentives to those NSPs that meet the consumer engagement and other expectations in the handbook:
  - A **targeted review** of an NSP's opex, capex and/or regulatory depreciation proposals where the proposal substantially meets the AER's expectations set out in the Handbook. For example, if an NSP can show evidence it has genuinely engaged with consumers on opex, has used the AER's preferred approach to the base-step-trend opex forecasting technique, includes none or few well justified step changes, and only proposed the same category specific opex forecasts as approved in prior decisions, the AER may decide to carry out a more targeted review of that NSP's opex.
  - Use of the **early signal pathway process,** which is available on application where an NSP is not proposing a material increase in expenditure. Where the AER agrees to use this process, it provides support during the pre-lodgement engagement process and will provide an early signal that it is likely to accept and those that will be subject to a targeted review.[60] The benefit for NSPs is that, where the proposal meets the AER's expectations, the AER may be able to narrow the matters requiring in-depth assessment and the proposal is more likely to be largely or wholly accepted at the draft decision stage (see Box 1).

56 The Commission gave the example that "it may be the case that a majority of affected consumers are unhappy with the visual impact of a proposed new line. If the NSP engages with consumers, it may decide that the best way to address the concerns of consumers would be to build the line underground, even if this is a more expensive option. When the AER considers the NSP's overall capex proposal, it should take into account that the proposed option will provide a higher quality of service in line with consumers' preferences and willingness to pay, above less expensive options which fall below the level of service demanded by consumers."

57 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Determination*, November 2012, pp. 26, 101 and 115.

58 The CCP's role is to inform the AER of key issues and areas of contention relating to an NSP's consumer engagement and regulatory proposal, and challenge the AER to ensure consumer interests have been assessed and given due consideration in its determinations. It is also expected to advise the AER on whether consumer views are appropriately reflected in proposals and the extent to which key issues and expenditure proposals have been presented to consumers in a balanced and comprehensive way. See AER, *CCP Terms of Reference*, July 2026.

59 AER, *Better Resets Handbook*, July 2024.

60 This 'early signal' is provided through an issues paper it is required to publish shortly after the proposal is submitted.

Box 1: Use of the early signal pathway process

Following publication of the Better Resets Handbook in 2021,[1] three DNSPs have been subject to the early signal pathway: Endeavour, Essential and SA Power Networks (SAPN).[2]

In both the Endeavour and Essential determination processes, which were carried out in 2023-24, the AER acknowledged the quality of the engagement undertaken and indicated in its issues paper those areas of the proposal that met its expectations and those where it would undertake a more targeted (narrowly scoped) review.[3]

In SAPN's determination process, which was carried out in 2024-25, the AER also acknowledged the quality of the engagement that had been undertaken. However, the AER found that the proposed increase in opex and capex (~20 per cent) did not meet the Handbook's expectations for 'steady growth in spending' and so was unable to provide an early signal of acceptance when it published its issues paper. The AER instead reverted to a more detailed review of most of SAPN's proposed expenditure.[4] While the AER ultimately accepted most of SAPN's regulatory proposal, SAPN did not derive any regulatory process benefits from the early signal pathway in this case.

Since the SAPN decision, the early signal pathway has not been used. This may be because the regulatory proposals that have followed have proposed material expenditure increases.

[1] AER, Better Resets Handbook, December 2021.

[2] In 2021-22, the AER also decided to undertake a more targeted review of Powerlink's 2022-27 proposal. In this case, the AER decided to largely accept Powerlink's proposal and only undertake a targeted review of a limited number of issues, because Powerlink had submitted a "well-informed initial proposal, underpinned by significant consumer engagement". See AER, *Final Decision: Powerlink Queensland Transmission Determination 2022 to 2027*, April 2022.

[3] See Essential Energy 2024-29: AER, *Issues Paper*, March 2023, AER, *Draft Decision - Overview*, September 2023 and AER, *Final Decision - Overview*, April 2024.Endeavour Energy 2024-29: AER, *Issues Paper*, March 2023, AER, *Draft Decision – Overview*, September 2023 and AER, *Final Decision – Overview*, April 2024.SA Power Networks 2025-30: AER, *Issues Paper*, March 2024, AER, *Draft Decision – Overview*, September 2024 and AER, *Final Decision – Overview*, April 2025.

[4] The AER ultimately accepted most of SAPN's proposal, but required a 3.4% reduction in capex AER, *Final Decision – Overview*, April 2025, p. vii.

The ECA and ENA have also taken steps to encourage NSPs to carry out more effective engagement with consumers. This includes the ECA-ENA annual Consumer Engagement Award, which recognises and promotes better practice in consumer engagement, including initiatives that listen to, involve and empower consumers.[61] ECA has also used its grants program to support not-for-profit consumer advocacy groups to participate in regulatory processes.[62]

2.3 We propose to explore opportunities to improve the efficiency of the revenue determination process

2.3.1 Potential issues with the current process include time and cost

The current revenue determination process spans multiple years

As shown in Figure 2.2, the current revenue determination process can take over three years to complete once the F&A stage and other preliminary activities are accounted for. This means NSPs and the AER currently spend more than half the regulatory control period developing and consulting on the revenue determination for the next regulatory control period.

The lengthening of the process can add to the costs that NSPs incur through the process, which are subsequently passed through to consumers. It may also introduce more rigidity (dynamic

61 Energy Consumer Australia, *Consumer Engagement Award*, 22 August 2024; Energy Networks Australia, *Ausgrid wins 2025 Energy Networks Consumer Engagement Award*, 12 September 2024.

62 Energy Consumer Australia, *Available grants*, last updated 1 June 2026.

inefficiency) into the process if it means that NSPs and the AER are unable to adapt as readily to changes that may occur in the lead up to the next regulatory period.[63]

A number of factors have likely contributed to the lengthening of this process, some of which may be as a result of the NER, while others may be a result of NSP or AER regulatory practices that have emerged over time.

One such factor that has likely contributed to the extended time frame is the extensive consumer engagement that NSPs are now undertaking in the **NSP regulatory proposal development stage**, which typically starts over three years before the commencement of the next regulatory control period.

The **F&A stage** has also contributed to the lengthening of the revenue determination process. While this was expected to be an optional stage of the process,[64] in practice the F&A stage has been triggered in every regulatory determination that has followed, often in response to a request by the relevant NSP

- In the case of DNSPs, this is because the F&A paper must set out the service classification and form(s) of control that will apply in the next regulatory control period, both of which can change from period to period.
- The reasons are less clear for TNSPs. This is because the rules currently only require the TNSP F&A paper to set out the AER's proposed approach to incentive schemes, depreciation and application of the AER's *Expenditure forecast assessment guidelines*, all of which are relatively static in nature.[65] As explained in section 2.2.2, the AER's proposed approach on these matters is also not binding on either the AER or TNSPs.[66, 67]

The extension of the **regulatory determination stage** from 10 months to 14 months through the 2012 *Economic regulation of network service providers* rule change has also contributed to the lengthening of the process.[68] This stage was extended to enable the AER to carry out more consultation with consumers and to prepare and publish an issues paper, draft and final determination.

The current revenue determination process is also resource intensive

The current revenue determination process requires NSPs, the AER, consumers and other stakeholders to dedicate **significant time and resources** to each stage of the process.

Indicative estimates provided by NSPs suggest that on an **aggregate basis**, NSPs spent around $190 million on their most recent revenue determination processes.[69] These costs are small relative to NSP's overall operating expenditure (collectively around $5.13 billion in 2025) but still matter as these costs are ultimately borne by consumers.

63 For example, if NSPs have to identify capex projects three years prior to the next regulatory control period to enable consumers to engage on the proposal, it may affect the way in which they consider new information that comes in that may suggest an alternative project.

64 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final determination*, November 2012, pp. 29 and 150.

65 For instance, TNSP F&A papers typically just confirm the AER's intent to use the current version of relevant incentive schemes and its standard approach to depreciation and the Expenditure Forecast Assessment Guidelines.

66 One exception is that the decision taken in the F&A on whether dual function assets will be subject to distribution or transmission pricing rules is binding.

67 Based on our review of recent TNSP requests and AER decisions to publish an F&A paper, it would appear that in most cases a new F&A paper has been published to refer to the most recent version of the incentive scheme. See for example, Transgrid, *Request for Amendment to F&A for 2028-33 Regulatory Control Period*, 30 October 2025 and AER, *Amendment to framework and approach paper - Transgrid*, December 2025.

68 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final determination*, November 2012, p. viii.

69 Estimates are based on information provided by 12 out of 13 DNSPs and all 5 TNSPs. Estimates by individual NSPs may use varying methodologies and should be considered indicative. Some NSPs that are currently in the midst of their revenue determination process provided estimates based on the actual costs incurred to date and an estimate of what they expect to incur over the remainder of the process. Costs were estimated for the non-reporting DNSP based on the average costs of the other DNSPs, adjusted for customer size.

The regulatory costs incurred by NSPs reflects:

- the information NSPs are expected to provide as part of their initial and revised regulatory proposals, including in response to regulatory information notices (RIN) issued by the AER to inform the regulatory determination process
- the complexities and increasing degree of forecasting uncertainty, which is resulting in NSPs having to undertake more extensive modelling and forecasting
- the extensive engagement NSPs are now conducting with consumers and other stakeholder/advisory groups.

This complexity is reflected in proposals themselves. In the recent round of regulatory determinations, most NSP regulatory proposals were 100-300 pages long and included between 150 and 200 attachments.[70]

Additional costs for the regulatory process are incurred by the AER and other stakeholders. The AER's resource requirements are influenced by the current regulatory timetable, set out in Table 2.1. The number of determinations made in each year varies significantly between years.[71] There may be value therefore in considering whether an alternative distribution would be more efficient.

Table 2.1: Current regulatory timetable

Regulatory Period	TNSPs	DNSPs	Interconnector	Total number
2022-272	AusNet (Vic), Powerlink (Qld)	n.a.	n.a.	2
2023-28	Transgrid (NSW), ElectraNet (SA)	n.a.	Murraylink	3
2024-29	TasNetworks (Tas)	Ausgrid, Essential, Endeavour, Evoenergy (NSW/ACT), PWC (NT), TasNetworks (Tas)	n.a.	7
2025-30	n.a.	Ergon, Energex (Qld), SA Power Networks (SA)	Directlink	3
2026-31	n.a.	AusNet, Jemena, CitiPower, Powercor, United Energy (Vic)	n.a.	5

Source: AER website.

2.3.2 There may be opportunities to improve the efficiency of the revenue determination process

The time, complexities and resources involved in the current revenue determination process give rise to significant regulatory costs, which in the NSP's case are ultimately passed through to consumers.

While these are not necessarily new issues, we consider there is merit in exploring whether there are any ways to **streamline or otherwise improve the efficiency of the current revenue**

70 This includes regulatory models, expert reports, business cases, consumer engagement reports, RIN responses and other attachments. AER register of regulatory determinations. See here.

71 When gas determinations are added in, the numbers range from 3 to 8 determinations in a year.

determination process, given the costs incurred by NSPs are ultimately borne by consumers. Such improvements could involve changes to the NER and/or changes to current NSP or AER practices.

This could, for example, involve making **incremental changes to one or more of the existing stages of the revenue determination process** (e.g. the F&A stage, NSP development of regulatory proposal stage and/or revenue determination stage) or more **fundamental changes** if it would better promote the NEO.

There may also be value in considering whether changes should be made to the **regulatory timetable** to provide for a more even distribution of regulatory determinations across years, and/or greater efficiencies by aligning certain determinations (e.g. by aligning determinations by jurisdiction,[72] or by NSP type).[73] We understand that any such change would require extensive transitional arrangements, so there would need to be clear benefits of making such a change (e.g. greater economies in decision making and reducing the AER and/or NSP resource requirements).

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?
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.
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.
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.

2.4 We propose to explore opportunities to improve the outcomes of the revenue determination process

Significant information asymmetries exist between the AER and NSPs throughout the revenue setting process. A number of regulatory techniques, including incentive mechanisms (discussed further in Chapter 3), are used to try and overcome these asymmetries. However, this task may be becoming more challenging in the context of the energy transition where the rate of change is increasing and expenditure is more often new and non-recurrent.

We are therefore proposing to consider whether changes to the current revenue determination process could lead to better regulatory decisions, promoting consumers' long term interests.

72 For example, so the AER would make a determination on the NSW/ACT TNSP and DNSP regulatory proposals at the same time.

73 For example, so the AER make a determination on all the TNSP regulatory proposals at the same time. Given the larger number of DNSPs, this may need to be divided into 2-3 groups.

2.4.1 The current process places significant onus on the AER to assess the prudency and efficiency of proposed expenditure

It is in NSPs' interests to improve their revenue outcome through the revenue determination process

In an ex ante framework, the revenue determination process sets networks' regulated revenues for the forthcoming regulatory period. A significant body of academic work and regulatory experience highlights a fundamental challenge in setting the expenditure allowances that underpin those revenues.[74] Networks hold better information than the regulator about their assets, operating conditions and likely expenditure requirements.

Economic theory demonstrates that, where an NSP's reported costs can influence its allowance and it has better information than the regulator about its assets, operating conditions and expenditure requirements, the regulatory framework may create incentives that favour higher expenditure allowances. These incentives can arise for a number of reasons, including that higher allowances may:

- **provide greater opportunity to outperform the allowance and retain efficiency gains.** Where actual expenditure is lower than the expenditure allowance, NSPs may retain some of the resulting benefits under the regulatory framework. This may occur when a network benefits from financing cost allowances that are retained until the RAB is updated for actual expenditure, or through explicit incentive schemes that share the benefits of efficiency improvements.
- **provide contingency against uncertainty and unexpected costs, reducing the risk that prudent expenditure is not recovered.** NSPs face uncertainty about the costs of delivering individual projects or programs of work, and expenditure forecasts may therefore incorporate conservative assumptions to ensure sufficient funding is available if costs are higher than expected.

This incentive is present in similar ex ante regulatory regimes. The UK's Water Services Regulation Authority (Ofwat) has recognised that regulated entities whose forecasts can influence their allowances may have an "incentive to submit high forecasts".[75] The UK's electricity regulator (Ofgem) has found evidence that suggests this incentive does materialise, with networks appearing to systematically submit expenditure forecasts above the revealed costs they later incurred.[76]

The AER adopts a number of techniques to assess whether proposed expenditure is considered prudent and efficient

The incentives noted above, combined with the significant information asymmetry that exists between NSPs and the regulator places significant onus on the AER to scrutinise and verify proposed expenditure as being prudent and efficient.

The AER uses a number of techniques to assess whether proposed expenditure reasonably reflects prudent and efficient expenditure, which have developed over time. Specifically for capex, these techniques include:[77]

74 Baron and Myerson (1982), "Regulating a Monopolist with Unknown Costs", *Econometrica*, pp 911, 921; Laffont and Tirole (1986), "Using Cost Observation to Regulate Firms", *Journal of Political Economy*, Volume 94, Number 3, Part 1, pp 614–641.

75 Ofwat,*Delivering Water 2020: Our final methodology for the 2019 price review*, 2017, pp 143–144.

76 Ofgem, *RIIO-2 Framework Decision*, 2018, p. 43. In water, Ofwat have sought to address the risk of high forecasts through their capex assessment process and mechanisms. See Ofwat,*Our final methodology for PR24 Appendix 9 Setting expenditure allowances*, 2022, pp 7-8 and Ofwat, *Delivering Water 2020: Our final methodology for the 2019 price review*, 2017, p 139. In telecoms, New Zealand's Commerce Commission also identified the incentive for regulated monopolies to 'overstate required expenditure', see Commerce Commission, *Chorus' price-quality path from 1 January 2022 – Final decision – Reasons paper*, p. 98, December 2021

77 AER, *Review of incentives schemes for networks, Final decision*, April 2023, p. 17.

- applying a replacement capex model to forecast replacement costs by asset category based on the age profile of assets, revealed replacement rates and revealed unit costs which allows benchmarking and comparison of unit costs and replacement rates across NSPs
- using revealed unit costs to forecast connections and augmentation expenditure
- adjusting payments under the Capital Expenditure Sharing Scheme (CESS) for deferrals
- applying a base-step-trend approach for IT and vehicles
- subjecting particular capex projects to detailed engineering reviews
- relying on market tested outcomes for major projects where possible.

As part of these techniques, the AER uses information gathering processes (such as Regulatory Information Notices) to collect detailed expenditure, asset and operational data. This data enables the AER to compare NSPs and across time. It also helps the AER to identify efficient costs and move future allowances towards the costs of a frontier-efficient firm.[78] The NER requires the AER to have regard to benchmark capex when assessing expenditure forecasts.[79] The *Better Resets Handbook* strengthens this expectation, asking networks to test capex from the top down at both the total and category levels.[80]

Other approaches used to manage information asymmetry and cost uncertainty include the introduction of the 'Bright-Line Tiered Test' under the CESS (discussed further in section 3.2.3). Specifically, the test reduces the CESS sharing rate from 30 per cent to 20 per cent where an underspend exceeds 10 per cent of the forecast capex allowance.[81] This reduces the reward available from securing an allowance materially above actual expenditure.[82]

The current propose-respond model puts NSP and AER objectives in tension through the revenue determination process

The current revenue determination process, administered through the propose-respond model, puts NSPs' and the AER's objectives in tension. An NSP's rational objective is to obtain an expenditure allowance that provides headroom for unexpected cost increases and create greater scope to outperform the allowance and earn higher revenues. The AER's objective is to only approve expenditure that reflects prudent and efficient levels, while making decisions under considerable information uncertainty.

This dynamic plays out in practice in an observable pattern through the propose-respond process. With some exceptions, the revenue determination process generally proceeds as follows:

1. an NSP submits an initial revenue proposal
2. the AER closely scrutinises the proposal and makes a draft determination which may reduce revenue compared to the NSP's initial proposal, and may seek further information on certain aspects of the proposal
3. the NSP submits a revised revenue proposal, which may propose revenue above the AER's draft determination
4. the AER makes a final determination.

78 A frontier-efficient firm is a benchmark firm operating at industry best practice. It delivers a given level of service using the lowest feasible inputs, having regard to its operating environment. The frontier moves over time as technology, management practices and production methods improve, requiring firms to innovate and increase productivity to remain at the frontier. See HoustonKemp, *Australian Gas Networks: AER gas price review*, 2016, p. 12; AER, *Explanatory Statement: Expenditure Forecast Assessment Guidelines*, 2013, pp 127-128.

79 AER, *Preliminary Annual Information Order: Electricity distributors*, 2023, p 5.

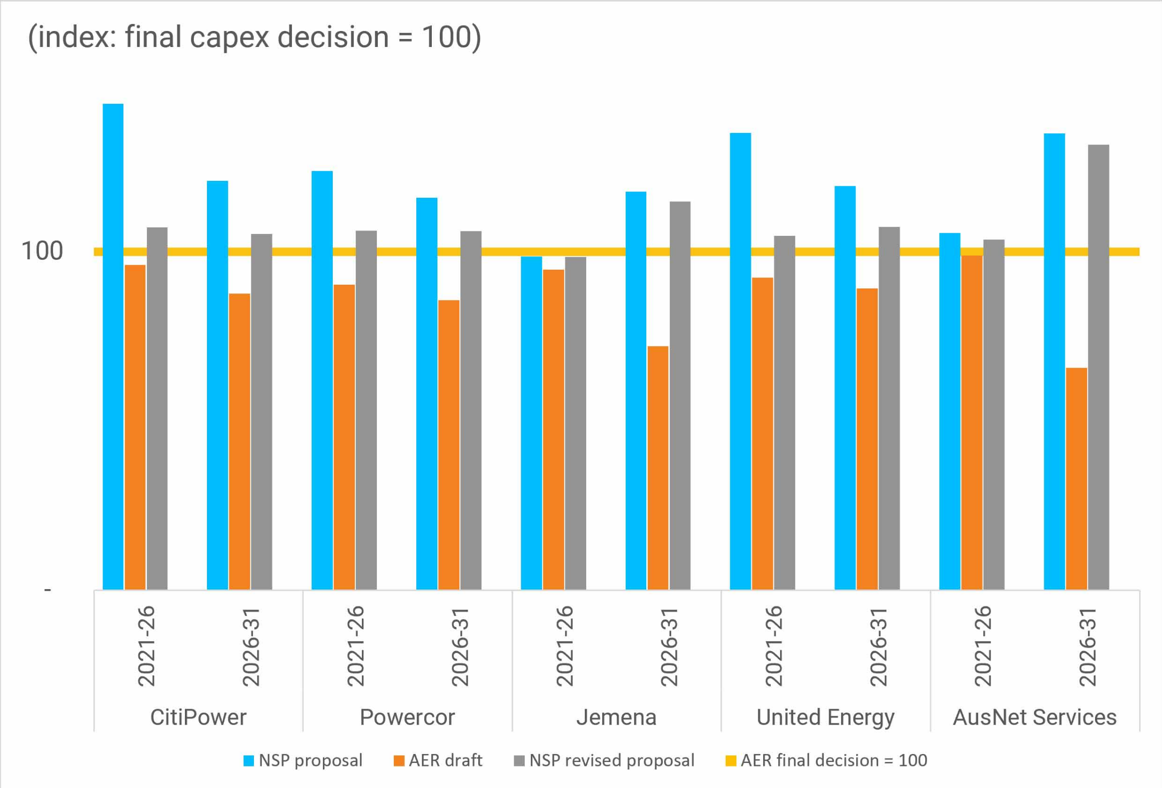
80 AER, *Better Resets Handbook*, July 2024, p 18.

81 AER, *Review of incentive schemes for networks: Final decision*, *April 2023*.

82 Ron Ben-David, *Regulating energy networks without the regulator: Chapter 1 – Capital Expenditure*, Monash Business School, May 2026.

This pattern is observable in the most recent determinations for the VIC DNSPs for the 2026-31 regulatory control period. We have focused on these NSPs as they have the most recent determinations and offer the largest same-jurisdiction comparison group. Figure 2.3 shows the capex allowance for these determinations and the previous determinations across the various steps of the determination process. Each step is indexed relative to the final AER decision (set at 100).

Figure 2.3: Victorian DNSP proposals, draft decisions, and revised proposals compared to final capex decision



Source: *AEMC analysis of public Post Tax Revenue Model (PTRM) data provided by the AER.*

This dynamic creates risks in both directions. If the AER approves expenditure above prudent and efficient level, costs to consumers may be higher than they otherwise need to be. But if allowances are set too low, NSPs may not have the ability to recover necessary costs which could lead to under-investment and reductions in service quality.

2.4.2 Estimating and assessing efficient costs may be becoming more difficult during the transition and higher capex allowances may have material impacts on consumers

Capex presents specific assessment challenges, which are likely to become more significant through the transition

The AER's task of assessing whether proposed expenditure is prudent and efficient is likely becoming more difficult. This challenge is more significant for capex, relative to opex, because opex is more recurrent in nature enabling greater use of historical comparisons and benchmarking tools.[83]

83 AER, *Better Resets Handbook*, July 2024, p 23.

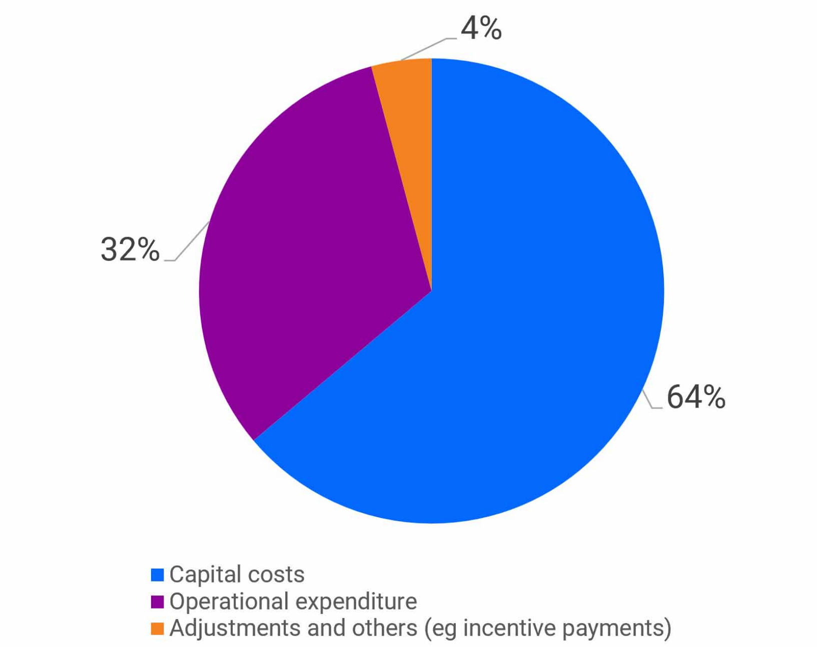
Capex, however, is generally more project-specific and less recurrent.[84] Historical expenditure and cross-network comparisons may therefore provide weaker evidence of the efficient cost of a proposed project. This places greater weight on the AER's assessment of network forecasts, project needs, options and cost estimates.[85] However, the AER may still benchmark standardised components, such as replacement expenditure.[86]

The energy transition may make assessing these forecasts more challenging as it changes investment and operational requirements. These costs may have few reliable historical comparators, making them less suited to whole-project benchmarking. Cost comparison and benchmarking work best where expenditure is broadly recurrent and can be compared consistently across networks and over time.[87]

Higher capex forecasts have long-lived impacts on consumers

Ensuring the framework supports efficient capex allowances matters for consumer outcomes because capex determines the majority of network revenues over time (see figure 2.4 below). The effects of capital expenditure also extend well beyond an upcoming control period. Consumers repay the cost of capex investments, together with the associated financing costs, over the economic life of those assets – often for well over 40 years or more.[88] Ensuring that capex forecasts reflect prudent and efficient costs is therefore critical to promoting consumers' long term interests.

Figure 2.4: Composition of average annual NSP revenue



Source: AEMC analysis of AER, *State of the energy market 2025*, 2025, and AER, *Electricity and gas networks performance report 2026*, 2026.

84 AER, *Review of incentive schemes for networks: Final decision*, April 2023, p 5.

85 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, pp 4–5.

86 AER, *Review of incentive schemes for networks: Final decision*, April 2023, p 5.

87 AER, *Better Resets Handbook*, July 2024, p 19.

88 See, eg, AER, *Issues paper: Powerlink electricity transmission determination 2027–32*, 2026, p 16-17.

2.4.3 There may be opportunities to support more robust capital expenditure proposals and determinations

Consumers may pay higher bills than necessary where capex allowances are set higher than required. As noted, the AER has already taken steps to alter regulatory mechanisms and to use enhanced tools to mitigate the risk information asymmetry poses to consumers.

The framework does not, however, have any mechanisms that specifically aim to incentivise NSPs to submit forecasts that are likely to better meet the AER's expectations around prudency and efficiency. Such mechanisms have been introduced in other regulatory frameworks. Box 2 below outlines examples of approaches that have been adopted elsewhere to address these issues, including where there is a risk that expenditure forecasts may be higher than ultimately required.

Box 2: Ofgem has used explicit incentive mechanisms to support more efficient cost allowances

Ofgem has used different regulatory mechanisms to address the information asymmetry problem over a number of price control periods:

- Ofgem's former Information Quality Incentive (IQI) was intended to make it theoretically optimal for companies to propose their true expected costs.[1] The IQI operated in two ways. It provided additional income to companies whose expenditure forecasts better matched Ofgem's independent assessment. It also provided a higher incentive rate to those companies, allowing them to retain a greater share of any subsequent outperformance.[2] The IQI approach was abandoned after it was considered to be overly complex and often misunderstood, including by the networks themselves.[3]
- Ofgem later moved towards a Business Plan Incentive that rewarded networks for submitting cost allowances that where ambitious and better matched the regulators' estimations of frontier efficient costs.[4] In addition to a qualitative assessment of business plans, Ofgem would also remove what they considered 'poorly justified cost estimates' and apply an additional penalty valued at 10 per cent of those removed costs.[5] After the initial application of the BPI Ofgem acknowledged that the incentive could be more 'targeted and simplified' and cognisant of the differences in resource (staff) levels between the regulator and the firm.[6] For the following application, Ofgem has retained the BPI but has made a number of refinements to the mechanism.[7]

[1] Ofgem, *RIIO-2 Framework Decision*, 2018, p 43.
[2] Ofgem, *RIIO-2 Framework Decision*, 2018, pp 80, 110.
[3] Ofgem, *RIIO-ED2 Network Price Control Draft Impact Assessment*, pp 21-22.
[4] Ofgem, *RIIO-2 Sector Specific Methodology – Core document*, 2019, p 103.
[5] Ofgem *RIIO-2 Sector Specific Methodology – Core document*, 2019, p 103.
[6] Ofgem, *Future Systems and Network Regulation: Framework Decision*, pp 36-38.
[7] Ofgem, *RIIO-3 Sector Specific Methodology Decision – Overview Document*, pp 71-72.

Against this background, we consider that the Review should further investigate the following areas:

- The potential to more explicitly incentivise NSPs to submit initial forecasts that better reflect frontier-efficient costs, drawing on mechanisms used in other regulatory frameworks and the lessons from their design and operation, and
- Non-incentive mechanisms and changes to the determination process that could reduce the information asymmetry between the AER and NSPs, including greater transparency and more consistent information requirements, the use of emerging data-analysis techniques such as

artificial intelligence, and modifications to particular stages of the process to reveal better information.

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.
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?

2.5 We propose to explore opportunities to ensure consumer interests are appropriately represented and reflected in regulatory proposals and determinations

The AEMC's 2012 Economic regulation of network service providers rule change,[89] together with the steps taken by NSPs, the AER, ECA and ENA over the last 10 years (see section 2.2.3), have led to substantial improvements in the way in which consumers are consulted and engaged as part of the regulatory determination process. During the AEMC's scoping work for this Review, stakeholders have nevertheless noted the potential for further improvements in this area.

We are therefore proposing to consider whether the current revenue determination process is enabling consumer interests to be effectively reflected in proposals and determinations, or if there are opportunities to make further improvements in this area.

2.5.1 What are the potential issues with how consumer interests are reflected in regulatory proposals and determinations?

NSPs have dedicated significant resources to consumer engagement, but recent AER decisions suggest there may be some limits to what consumers can effectively engage on

Indicative estimates provided by NSPs suggest that on an aggregate, NSPs spent around $35m on consumer engagement in the last round of revenue determinations.[90] While significant time and resources have been dedicated to consumer engagement, the AER has clarified in some of its more recent determinations that consumer engagement does not displace its role in scrutinising expenditure, particularly when there is a significant uplift in expenditure. Elaborating on this further, the AER stated that:[91]

"Consumer support is an important part of this assessment. However, even where it is possible to say that a proposal is reflective of consumer views and preferences, this does not displace the AER's role in carefully testing and assessing the prudency and efficiency of proposed expenditure.

89 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final determination,* November 2012

90 The aggregate costs have been calculated using consumer engagement costs provided by 12 out of 13 DNSPs and 3 out of 5 TNSPs, together with AEMC estimates for the non-reporting NSPs. For the non-reporting NSPs the AEMC has estimated their costs based on the average cost per customer (DNSPs) and average cost per volume electricity transported (TNSPs) of the other reporting NSPs. The estimate is indicative only and reflects both assumptions made by NSPs in reporting their costs and assumptions made by the AEMC.

91 AER, *Draft decision: CitiPower electricity distribution determination 2026-31 – Overview*, September 2025, p. v.

Submissions have emphasised the importance of this scrutiny in ensuring desired outcomes are delivered at the lowest sustainable cost."

This was reflected in recent Victorian DNSP determinations. The AER recognised the role of consumer engagement, but did not fully accept some expenditure that had consumer stakeholder support because aspects of the proposals were insufficiently justified to support the forecasts .[92]

The AER also pointed to the following feedback obtained from AusNet's Coordination Group.

"…there are challenges for consumers participating in early engagement in providing unequivocal support for specific proposals. This is particularly the case for proposed levels of expenditure which in many cases are based on detailed technical analysis to which they have limited exposure, and for which amounts and inputs ultimately included in a proposal have changed, sometimes materially, since consumer deliberations on a specific area."

These statements highlight some of the potential challenges and limits associated with consumer engagement, which have also been identified in other sectors.[93]

Stakeholders have raised questions about how effectively consumer interests are represented and whether the current revenue determination process supports effective engagement

NSPs currently use a broad range of techniques to engage with their customers, including customer forums, surveys, interviews and online engagement portals. Most NSPs have also established customer consultative groups, which include a number of independent customer advocates who are renumerated for their time. While NSP engagement is broad ranging, questions have been raised in the past about how to ensure customer consultative groups are representative of a network's customer base and have the capability and time to effectively advocate for customer outcomes.[94]

More generally, there is a question as to whether the engagement that is being undertaken can adequately capture the different needs, circumstances and preferences of both current and future consumers, including where consumers may place different weight on price, reliability, service levels and future network investment.

Through our early engagement, questions have also been raised about **the extent to which the revenue determination process is supporting effective engagement**, with, particular questions raised about:

- **Role and weight of consumer views**, with some stakeholders noting uncertainty about the role that consumer views should play in NSP regulatory proposals and AER determinations, and the weight the AER should place on the consultation outcomes when assessing whether an NSP's proposed expenditure is prudent and efficient, and other aspects of the regulatory proposal.
- **Complexity of revenue determinations**, with some stakeholders raising that there may be some aspects of a revenue determination that are too complex or technical for individual consumers to engage effectively, and whether there are topics where consumers may have limited ability to meaningfully influence outcomes.

92 AER, *Final decision - CitiPower Electricity Distribution Determination (1 July 2026 to 30 June 2031) – Overview*, April 2026, p. vii; Customer Advisory Panel, *Report on the AER's Draft Decision and the United Energy Revised Regulatory Proposal 2026-31*, January 2026, p. 6; AER, *Final Decision - AusNet Services Electricity Distribution Determination (1 July 2026 to 30 June 2031) – Overview*, April 2026, pp. ix-x.

93 This issue was also raised in a review of TasWater's PSP5 customer engagement conducted by the consulting firm Sapere. The review considered that, where respondents have not had the time, resources and skills needed to be sufficiently informed, limited weight should be placed on customer and community engagement when assessing prudency and efficiency. It concluded that customer engagement should be more focused on gathering information that only customers can provide, using customers to challenge decisions and building trust with the community. See Sapere, Review of TasWater's Operational Expenditure - FINAL Report for the Office of the Tasmanian Economic Regulator (OTTER), April 2026, pp. 7-8.

94 Ausgrid, *Submission to AEMC Electricity Networks Economic Framework Review*, July 2020, p. 5.

- **The time available to develop revised proposals**, with some stakeholders noting the current 45-day business day response period in the NER was too short to enable meaningful engagement between NSPs and their customers.

The issues identified above raise important questions about whether:

- the current framework provides sufficient clarity about the role of consumer engagement in the revenue determination process, and
- there are more effective ways to understand and reflect consumer preferences in NSP proposals and AER determinations, particularly as the energy transition progresses.[95]

Importantly, these issues are not unique to the NEM. Other regulated sectors and jurisdictions have adopted different approaches to elicit and reflect consumer preferences in the revenue determination process, and some have already implemented or are considering refinements to those approaches.[96] Box 3 provides an overview of how the consumer engagement model is evolving in Scottish water regulation to address some of these issues.

Box 3: Consumer engagement and research group in Scottish water regulation

The Scottish water regulatory framework[1] provides an example of how a formal consumer engagement model has evolved from direct negotiation between the business and customer representatives towards a model focused on independent challenge, candour and research.

For the 2027–33 regulatory period, the Water Industry Commission for Scotland (WICS) has moved away from the earlier "negotiate-arbitrate" approach[2]. WICS considered that this model did not fully address information asymmetries and could create challenges for customer representatives when considering complex issues such as affordability and investment needs to meet the industry's challenges.[3]

The revised model consists of three pillars of work for consumer engagement: challenge, evidence and confirmation. Challenge is provided by the Independent Customer Group (ICG), which is hosted by Scottish Water but operationally independent. The ICG helps ensure that the Scottish Water business plan has customer support and, in turn, also the WICS's final determination.

A key difference between the consumer engagement approach in the NEM and the Scottish model is the evidence pillar, which is provided by the Customer and Community Research Co-ordination Group (CRCG). The purpose of the CRCG is to understand and provide an evidence base of current and future customer and community requirements.[4]

Source: [1] The Water Industry Commission for Scotland (WICS) regulates a single publicly owned utility, Scottish Water.

Source: [2] For information on the earlier model for Scottish water regulation used in 2015-21 regulatory period and 2021-27 regulatory period see: Customer Forum for Water in Scotland, *The Customer Forum – Legacy report*, February 2015.

Source: [3] Water Industry Commission for Scotland, *Solving the customer engagement conundrum*, accessed 15 July 2026.

Source: [4] Water Industry Commission for Scotland, Consumer Scotland and Scottish Water, *Customer Engagement in the Strategic Review of Charges for 2027-2033 - Tri-partite Memorandum of Understanding*, November 2024.

95 For example, the Energy Efficiency Council's 2026 Power Dynamics white paper recommends focusing stakeholder engagement on a smaller number of deep deliberative processes for core issues. The paper notes that this can build stakeholder knowledge and capability and reduce the complexity and cost of a broad range of consultations for both the institutions conducting the consultations and stakeholders. This paper also recommends increased funding for consumer representation and research. In doing so, the paper notes that effective consumer advocacy requires technical, economic, legal and governance expertise, a continually updated understanding of consumer needs, sound governance and relationships with regulators and other stakeholder groups. See Rob Murray-Leach, *Power Dynamics: Energy Governance in Australia White Paper*, Energy Efficiency Council, Melbourne, April 2026, pp. 43-44.

96 For example, IPART's 3Cs water regulation framework, the PREMO model used in Victorian water regulation, Tasmanian water regulation, Ofgem's RIIO-3 electricity network regulation and Ireland's electricity network regulation. See IPART, *Our water regulatory framework*, November 2022; Essential Services Commission, *Water Pricing Framework and Approach: Implementing PREMO from 2018*, October 2016; Essential Services Commission, *Essential Services Commission Regulatory Priorities 2026–27*, July 2026; IPART, *Handbook - Water regulation*, July 2023; Ofgem, *Future Systems and Network Regulation Core Document*, October 2023; Commission for Regulation of Utilities, *Price Review Six - Regulatory Framework*, July 2025.

2.5.2 There may be opportunities to improve the way in which consumer interests are taken into account in NSP proposals and AER determinations

The issues identified above suggest there may be opportunities to improve the way in which consumer interests are taken into account in NSP regulatory proposals and AER regulatory determinations. These opportunities range from incremental changes to the existing approach, through to more substantial changes to the role that consumer engagement plays in the revenue determination process.

We may explore the following issues throughout the Review:

- **Is there sufficient clarity about the role of consumer engagement in the revenue determination process?** Consumer views can help inform the AER's assessment of proposed expenditure, while recognising that they are only one factor the AER must consider alongside the relevant capex and opex criteria.[97] The extent to which consumer engagement can inform decision-making may therefore vary depending on the nature of the issue, particularly where proposals involve complex technical analysis, forecasting uncertainty or long-term trade-offs between current and future consumers. At the same time, consumer views can provide important evidence about consumer priorities, preferences and trade-offs. There may therefore be value in considering whether further guidance (which need not be rules-based) is needed on the role of consumer engagement in the revenue determination process.
- **Is there a need for more research or analysis to understand and reflect consumer preferences?** This could include research to understand and provide an evidence base of current and future customer and community preferences to inform the revenue determination process (see the Scottish Water example in Box 3). It could also include revealed consumer preferences analysis, which looks at how consumers respond to different network service, price or reliability outcomes.
- **Could energy service providers play a more prominent role in representing consumer preferences in the revenue determination process?** In our recent *Pricing review - Electricity pricing for a consumer-driven future*, we recommended that energy service providers play a more active role in managing pricing complexity and offering consumers energy plans that reflect their needs and behaviour and deliver value without requiring expert knowledge or constant engagement.[98] There may therefore be value in considering whether the revenue determination processes should better account for energy service providers' insights into consumer preferences.
- **Are there process changes that could support more meaningful consumer engagement?** This could include considering whether the time available for stakeholders to engage with draft determinations and revised regulatory proposals is sufficient, particularly where proposals involve complex technical issues or material changes from the initial proposal.

We are seeking stakeholder views on whether the current framework appropriately accounts for consumer preferences in the revenue determination process, and whether there is a need to improve the identification and incorporation of consumer preferences. Any changes should be effective and proportionate, having regard to their costs and regulatory burden.

97 NER, clauses 6.5.6-7 and 6A.6.6-7.

98 AEMC, *The pricing review - Electricity pricing for a consumer-driven future, Final determination,* June 2026, pp. v-vi.

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?
2. Should changes be made to how consumer preferences are identified, represented and reflected in the revenue determination process?
    a. Is there a need to clarify how consumer views should be used and are there certain topics where consumer views are most relevant?
    b. Could retailers play a more prominent role in representing consumer preferences in the revenue determination process, recognising 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?

3 We will explore the incentive arrangements that apply to NSPs

In the NEM, a key regulatory tool for promoting consumer outcomes is the use of incentives. The regulatory framework includes both implicit incentives created by the ex ante framework as well as a number of explicit incentive schemes that have been introduced over time. This chapter sets out:

- why the framework uses incentives and the overall objectives of this part of the framework (section 3.1)
- how the current framework operates, including a discussion on each of the incentive schemes currently in operation (section 3.2)
- the potential issues with the incentive framework we propose to investigate further, including:
    - the balance of incentives for NSPs to undertake capex relative to opex (section 3.3)
    - implications for incentives as DNSPs take on DSO functions (section 3.4)
    - incentives for efficient network utilisation (section 3.5), and
    - incentives for NSPs to undertake innovation (section 3.6).

3.1 The framework uses incentives to align NSP and consumer interests

The overall objective of the incentive framework is to ensure regulated services are provided by NSPs as efficiently as possible, at a level of service quality that aligns with what consumers value. This is encapsulated by the NEO, which seeks to promote economic efficiency (including consideration of emissions reduction).

There are a number of components to economic efficiency that the framework must seek to promote. Consumers' long term interests are promoted when NSPs deliver services as efficiently as possible, the services provided and level of quality align with what consumers value, and NSPs improve and innovate over time to reduce costs over the long-run. In economic terms, these outcomes are referred to as *productive*, *allocative* and *dynamic* efficiency (summarised in Box 4).

Box 4: *The NER economic regulatory framework aims to promote productive, allocative and dynamic efficiency*

Productive efficiency refers to the production of goods and services at the lowest possible cost, given available technology and input prices. In the context of electricity networks, it means that network services are delivered using the least-cost combination of capital and operating inputs, without waste or excess capacity.

Allocative efficiency refers to the allocation of resources to their highest-value uses, such that the goods and services produced reflect what consumers value most. In electricity networks, this means providing the level and mix of network services — including reliability, security and hosting capacity for CER — that consumers are willing to pay for, rather than a level determined by engineering standards or historical practice alone.

Dynamic efficiency refers to the efficient allocation of resources over time, including efficient investment in long-lived assets and ongoing innovation in products, services and processes. For electricity networks, it means that investment occurs when and where it delivers net benefits to consumers over the long term, and that the framework encourages the adoption of new technologies and business models as conditions change.

The framework uses incentives (as well as other regulatory tools such as obligations and standards) to achieve these outcomes. When well-designed, they align NSPs' interests with consumers' interests and create the possibility of win-win outcomes. That is, consumer outcomes are improved by NSPs pursuing their own interests.

Incentives can also be used as a tool for addressing the information asymmetries that exist between the regulator and any regulated business. Where incentives are aligned, they can reduce the need for the regulator to scrutinise the individual decisions of a network business which in practice may be resource intensive and difficult to independently evaluate.

3.2 The framework includes implicit incentives which are adjusted through explicit incentive schemes

3.2.1 The ex ante framework incentivises cost savings

The ex ante framework (described in Chapter 2) creates an incentive for NSPs to reduce expenditure over time by setting capex and opex allowances ahead of time and allowing NSPs to benefit (or bear costs) from any under-spend (or over-spend) of the allowance.[99]

This creates an incentive for NSPs to reduce actual costs below their allowance. It enables the NSPs to earn higher returns in the short term when they reduce their expenditure during the regulatory period. Consumers also benefit from this outperformance (when driven by efficiency improvements) because cost information is revealed to the regulator and can be incorporated into future revenue determinations. In this way the revenue determination process is a repeat game that incentivises NSPs to improve their efficiency and reveal this information to the regulator, which benefits consumers over the long-term.

While this overall approach can encourage NSPs to seek out cost efficiencies, without additional adjustments it can also incentivise actions that are not in consumers interests. The AEMC and the AER have introduced additional explicit incentive schemes over time to correct these inefficiencies created by the framework. These issues that have been identified and incentive schemes that have been introduced to address these include:

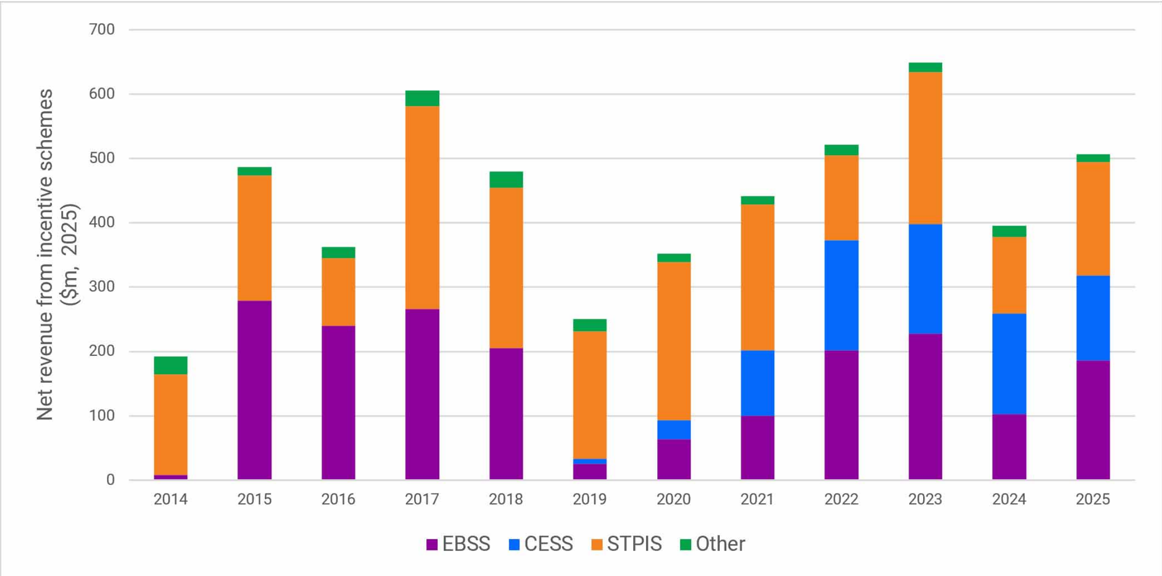
- *NSPs may face declining incentives to achieve expenditure efficiencies throughout the regulatory control period* because they are unable to retain the benefits of any underspend for as long. To address this, the **Efficiency Benefit Sharing Scheme (EBSS)** was introduced for opex and the **Capital Expenditure Sharing Scheme (CESS)** was introduced for capex.
- *NSPs may be incentivised to pursue capex-based solutions (ie poles and wires options) over opex-based solutions (ie non-network options - NNOs)* because NSPs earn a regulated return on capex but not opex and NNOs may provide broader whole of system benefits that do not accrue to NSPs. The **Demand Management Incentive Scheme (DMIS)** was introduced to incentivise DNSPs to undertake NNOs and the **Demand Management Innovation Allowance Mechanism (DMIAM)** was introduced to support research and development by both DNSPs and TNSPs in innovative non-network solutions.
- *NSPs may be incentivised to pursue cost efficiencies at the expense of service quality.* This means that NSPs may reduce service below a level that consumers value and would otherwise be willing to pay for.

99 Without the EBSS and CESS (discussed further below) an NSP still has an incentive to reduce expenditure below its allowance, but the incentive declines over the regulatory period. See section 3.2.2 for further detail and worked examples.

- The **Service Target Performance Incentive Scheme (STPIS)** was introduced to incentivise NSPs to provide network reliability at a level that aligns with what consumers value and are willing to pay for.
- The **Export Service Incentive Scheme (ESIS)** was introduced to incentivise DNSPs to provide export services to consumers at a capacity and quality that aligns with their willingness to pay.
- The **Customer Service Incentive Scheme (CSIS)** was introduced to incentivise DNSPs to provide broader customer service (beyond network reliability) in line with what consumers value, including aspects such as the timeliness of new connections, the quality and accuracy of new connections and complaint handling.

The majority of incentive payments have been made to DNPSs and have related to the EBSS, CESS and STPIS, as shown in Figure 3.1 below. Incentive payments represented around 4.4 per cent of total revenue for DNSPs and around 0.4 per cent of total revenues for TNSPs in 2025, [100] or in total around $45 per customer in 2025 (see Figure 3.2).

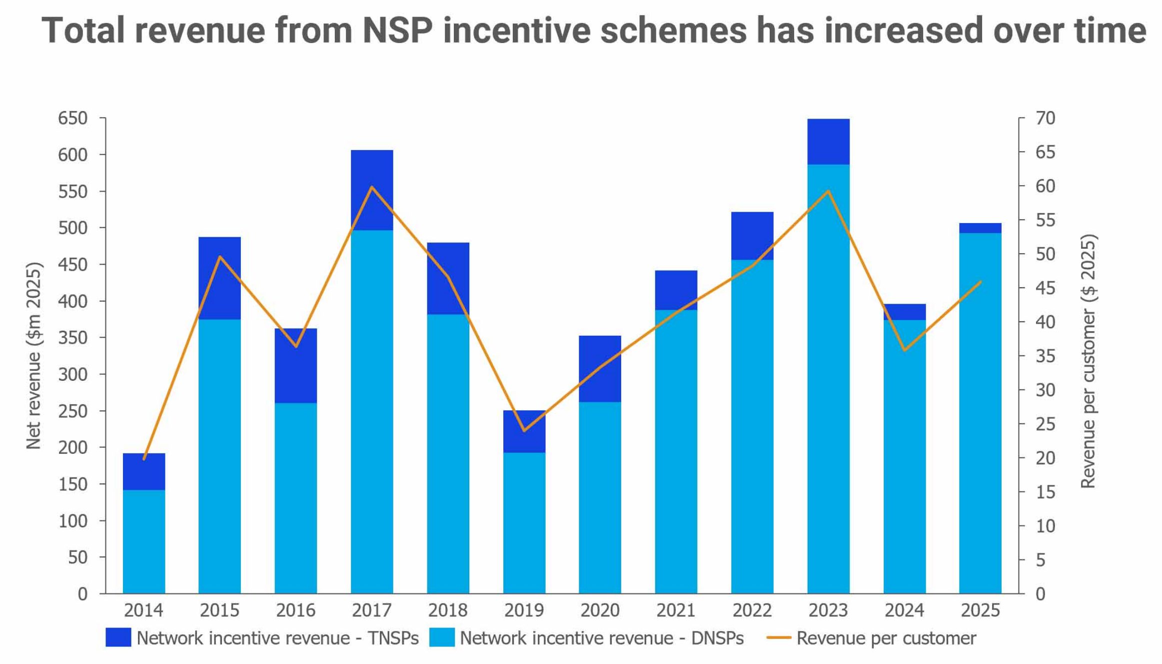
Figure 3.1: Revenue from incentive schemes; by incentive scheme ($m real 2025)



Source: AER, Electricity and gas networks performance report 2026, July 2026, p 14;

100 AER, Network performance report, July 2026, p 14.

Figure 3.2: Total revenue from incentive schemes; TNSPs and DNSPs ($m real 2025)



Source: AEMC, based on data provided by the AER.

Each incentive scheme is discussed in more detail below.

3.2.2 The Efficiency Benefit Sharing Scheme

The EBSS levelises opex efficiency incentives over time

The AER introduced the EBSS in its current form in 2013 to make the incentive for NSPs to pursue opex efficiencies consistent over time.[101] Without the EBSS, an NSP only retains the benefit of any underspend of its opex allowance for the balance of the regulatory control period, due to the way NSPs' opex allowances are set using the 'base-step-trend' method.[102] Under this approach, opex allowances for the next regulatory control period are set with reference to a 'base' year in the current period (usually year 3 or 4), based on the assumption that opex is largely recurrent. Any opex efficiency savings by an NSP that were observable in this base year were then factored into the next regulatory period's allowance and therefore the benefits were lost by the NSP. In general, this resulted in declining rewards for cost reductions throughout the regulatory period and low incentives in the final years (see Box 5).[103]

101 AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013. The EBSS has been in place since the AER commenced economic regulation of NSPs. The EBSS commenced for TNSPs in 2007 and commenced for DNSPs in 2008.

102 Under this method, an NSP's opex allowance for the next regulatory control period is set with reference to a 'base' year in the previous period (usually year 3 or 4) provided the AER considers the actual expenditure in that year reasonably reflects prudent and efficient expenditure. This is then adjusted for 'step' changes in expenditure, such as from new regulatory obligations. This is then further adjusted for 'trend' changes in factors such as output, real prices and productivity. Source: AER, *Expenditure forecast assessment guideline for electricity distribution*, June 2024.

103 AER, *Review of incentives schemes for networks*, Final decision, April 2023, p9.

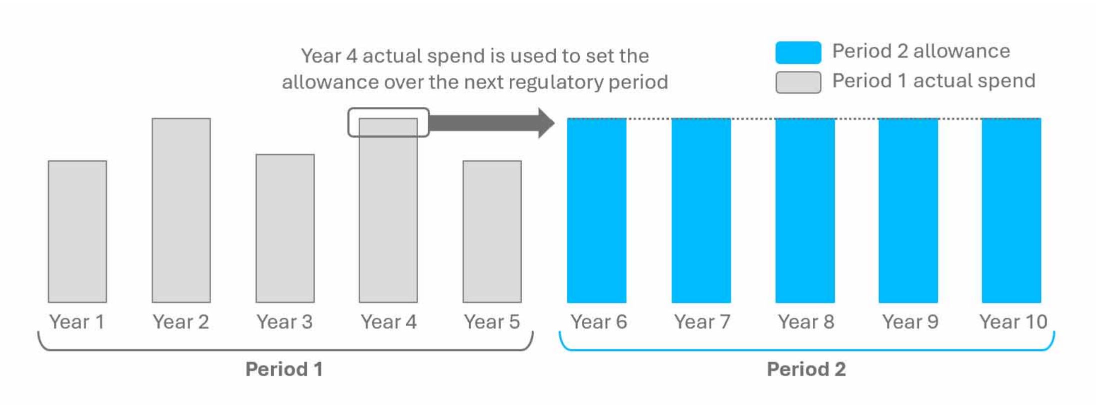
Box 5: How the EBSS operates

If there is no EBSS

Under the base-step-trend (BST) approach, operating expenditure allowances for a future regulatory period are based on actual expenditure in a designated base year in the current period. Absent an EBSS, this means that the value of an efficiency improvement (or saving) to both consumers and network businesses depends on when it occurs.

To illustrate this, let's start with how actual operating expenditure in one regulatory period is used to set allowed operating expenditure for the next. *Figure 1* below shows how in that example actual expenditure in year 4 of the first period (in grey) is used to determine the allowance in the second (in blue).

Figure 1: Applying the BST approach

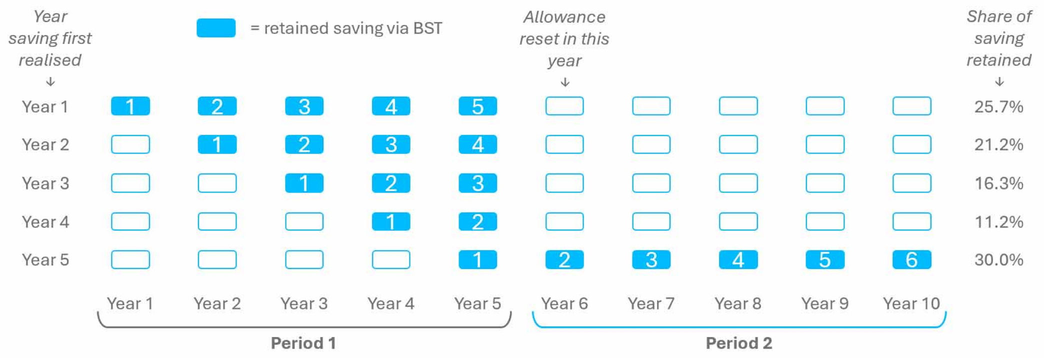


Once an allowance is set for a regulatory period, a network business can retain any saving it makes relative to that allowance until the allowance is reset. In this way, a permanent (or recurring) saving first realised in year 1 can be retained for years 1 through to 5 (i.e., 5 years) before it is reflected in the allowance for year 6 onwards. If it is first realised in year 2, then it is retained for years 2 to 5 (i.e., 4 years), and so on. If the saving is first realised in year 5, then it is retained for years 5 through to 10 (i.e., 6 years), before it is reflected in the allowance for year 11 onwards. This occurs because the allowance for the second period is set based on year 4 actual spend rather than year 5 actual spend (which is unknown at the time the allowance is set).

The graduated saving is illustrated in *Figure 2* with the solid blue squares indicating the number of years that a network business retains the saving for. It shows how the number of retained years drops from 5 if the saving is realised in year 1 down to just 2 if realised in year 4, before jumping up to 6 if realised in year 5.

The period of retention also translates into a *share* of retention (in per cent terms), which measures the share of the initial saving that is retained by the network business in present value terms. For a given discount rate, the share increases the longer the saving is retained for and vice versa. To illustrate, *Figure 2* also shows the retention share that corresponds to a given year that a saving is first realised. (These shares were calibrated by setting the discount rate used in the present value calculations to 6.1 per cent so that the retention share for a 6 year retention is 30 per cent).

Figure 2: How long a permanent saving is retained for without an EBSS



Note: The retention share is calculated using the following formula where 'N' is the number of years retained and 'D' is the rate of return: 1-(1+D)^(N-1). When the retention period (N) is 6 years and the discount rate (D) is 6.1 per cent, the retention share is 30 per cent.

Without an EBSS, network businesses face different incentives to realise operating expenditure savings across the regulatory period. They also face an incentive to increase operating expenditure in the base year, which increases their allowances for the next regulatory period.

If there is an EBSS

The EBSS was introduced to address these issues by ensuring that network businesses can retain the benefit of any saving for 6 years before it is passed through to consumers through lower future allowances, irrespective of when during the regulatory period the saving is realised.

This is illustrated in *Figure 3*. The grey squares show the additional years that a saving is retained for once an EBSS is in place. The outcome is that the share of the saving retained by the network business is the same for all years. (As above, this equates to a 30 per cent share if a discount rate of 6.12 per cent is used).

Figure 3: How long a permanent saving is retained for with an EBSS

Although the illustrations above refer to savings, the same logic applies equally to overspends. With an EBSS, the network business must retain the cost of that overspend for 6 years before it is shared with consumers via higher allowances.

Source: AEMC

The base-step-trend approach also created incentives for NSPs to time expenditure strategically instead of in line with overall cost minimisation. Without the EBSS, it may be in NSPs' financial interests to defer cost savings from late in one regulatory control period to early in the next control period, because savings can be retained by the NSP for longer.[104] Further, because an NSP's allowance for the next regulatory control period is set with reference to a base year in the previous period (usually year 3 or 4), NSPs had a strong incentive not to undertake cost savings in those years.[105]

The EBSS allows NSPs to retain opex under- or over-spend for six years

The EBSS creates a consistent incentive to reduce costs over time by rewarding or penalising any under- or over- spend of the opex allowance for a period of six years. As a result the incentive to reduce opex is the same in the first year as it is in the fifth year of the regulatory control period.

Beyond the six years consumers retain or bear the benefit or cost into perpetuity. In net present value terms, consumers retain the majority of the benefit of any underspend, with the exact sharing ratio depending on the weighted average cost of capital at the time. At the time the EBSS was established the sharing ratio was estimated at approximately 70:30 between consumers and NSPs.[106] The same ratio applies symmetrically to allowance overspends.

The AER also has the ability to exclude certain categories of expenditure from the EBSS — for example, cost categories that are not forecast using a single year revealed cost forecasting approach, or where a base-year adjustment would distort outcomes — to ensure carryovers reflect genuine efficiency changes rather than reclassification, deferral or accounting effects.[107]

The EBSS has generally achieved its objectives

The AER reviewed the performance of the various incentive schemes in 2023. The AER found the EBSS, together with the AER's approach to forecasting opex and benchmarking, had driven opex down significantly, with opex per customer falling by:[108]

- 30 per cent in real terms at the distribution level between 2011-12 and 2020-21 (from $412 to $287 per customer per annum)
- 16 per cent in real terms at a transmission level between 2015-16 and 2020-21 (from $68 to $57 per customer per annum).

The AER also observed that the EBSS has had strong information revelation properties and concluded that, combined with benchmarking, the EBSS had been successful in driving opex efficiency gains.[109]

Since the AER's review both DNSP and TNSP actual opex has trended upwards. Key drivers of growth for DNSPs included increases in expenditure related to natural disasters and bushfires, cyber and other information and communications technology (ICT) expenses, as well as output growth and real price growth.[110] Primary factors of TNSPs' opex growth included factors such as cyber ICT expenses, insurance premiums and costs related to ISP projects.[111] Overall, actual expenditure has generally been lower than forecast for both TNSPs and DNSPs, suggesting the

104 AER, *Efficiency benefit sharing scheme for electricity network service provides*, November 2013, p. 4-5.

105 AER, *Efficiency benefit sharing scheme for electricity network service provides*, November 2013, p. 4-5. Opex allowances are generally set using the 'base-step-trend' model whereby the 'base' for the opex allowance is year 3 or 4 in the previous regulatory control period which is then adjusted for 'step' changes in expenditure and 'trend' growth in costs. The EBSS is designed to work with the base-step-trend forecasting approach to provide a levelised opex incentive.

106 AER, *Efficiency benefit sharing scheme for electricity network service provides*, November 2013, p. 5.

107 AER, *Efficiency benefit sharing scheme for electricity network service provides*, November 2013, p. 7.

108 AER, *Review of incentives schemes for networks*, Final decision, April 2023, p11.

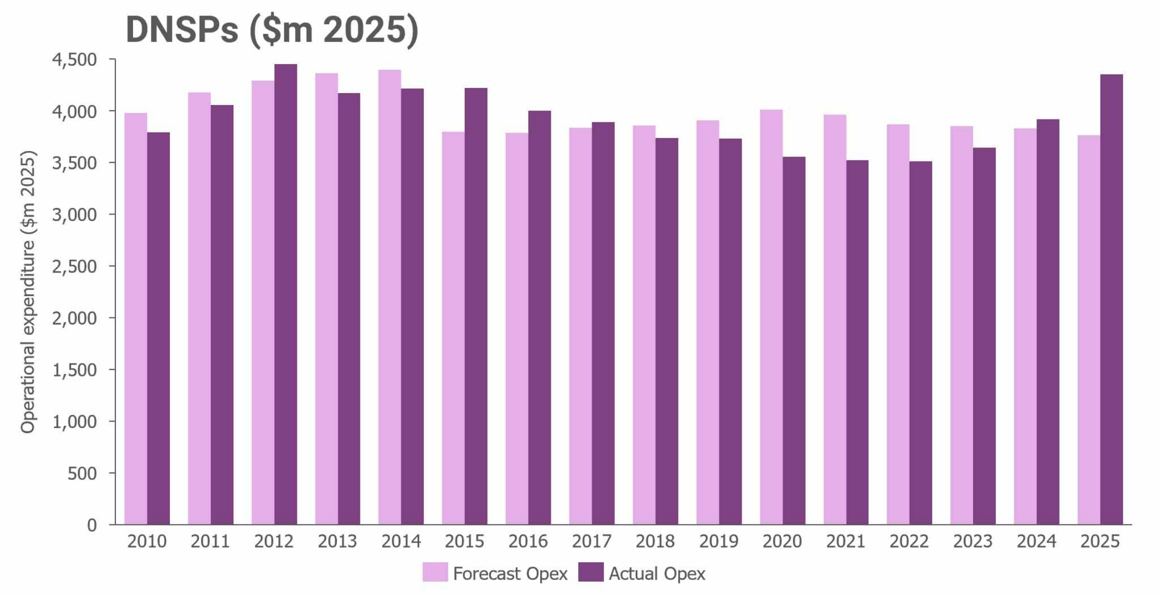
109 AER, *Review of incentives schemes for networks*, Final decision, April 2023, p12

110 See for example the AER's final determinations for SAPN 2020-25, Energex 2020-25 and AusNet 2021-26 regulatory control periods.

111 See for example the AER's final determinations for Powerlink 2022-27 and Transgrid 2023-28 regulatory control periods.

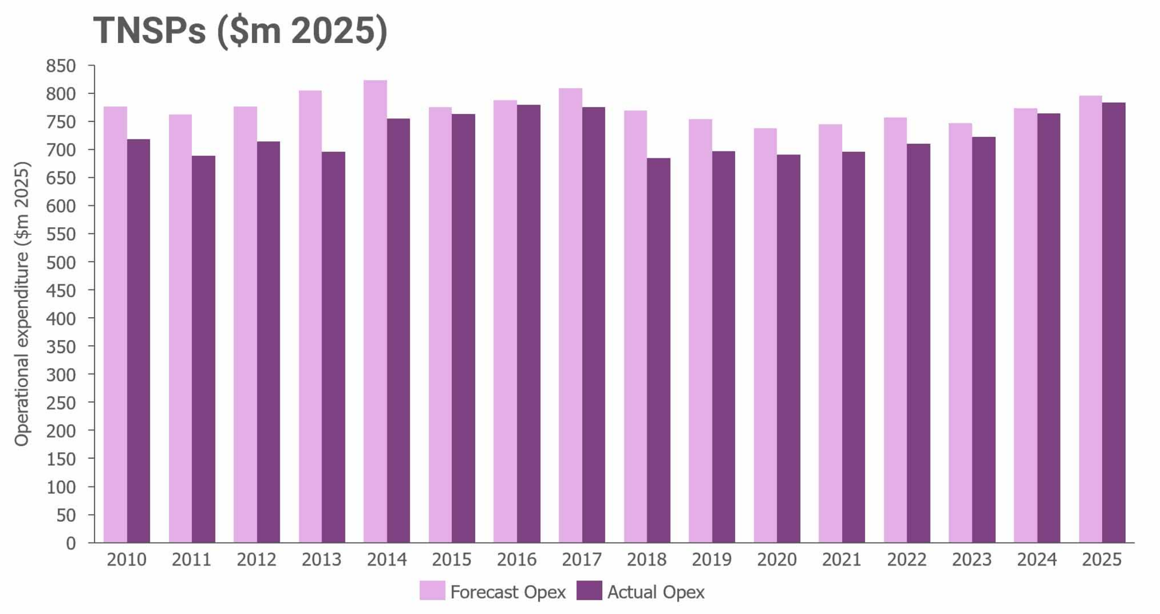
EBSS has been effective at incentivising NSPs to find efficiencies and outperform their opex allowances.[112] This represents a good outcome for consumers, to the extent that initial allowances reasonably reflect prudent and efficient levels, as consumers retain the majority of these savings over the long term.

Figure 3.3: Forecast and actual electricity operational expenditure by year - DNSPs ($m real 2025)



Source: AEMC, based on data provided by the AER.

Figure 3.4: Forecast and actual electricity operational expenditure by year - TNSPs ($m real 2025)



Source: AEMC, based on data provided by the AER.

112 The large difference between forecast and actual expenditure in 2022 is largely attributable to lower-than-expected demand growth resulting from the COVID-19 pandemic.

3.2.3 The Capital Expenditure Sharing Scheme

The CESS strengthens incentives for efficient capex

The AEMC introduced the CESS in 2012 due to regulator concerns at the time that the incentive for NSPs to incur capex efficiently declined over the regulatory control period and that any expenditure above the allowance was not subject to any regulatory scrutiny.[113] Without the CESS, the primary incentive for NSPs to reduce capex came from the ability to retain the financing benefits (return on capital) on avoided capex throughout the period. However, this benefit reduces throughout the regulatory control period as avoided capex towards the end of the period would accrue relatively little financing benefit before the RAB is rebased for actual expenditure. Similarly, the penalty for over-spending the allowance declined over time, with no meaningful penalty close to the end of the regulatory control period.[114]

Box 6: How the CESS operates

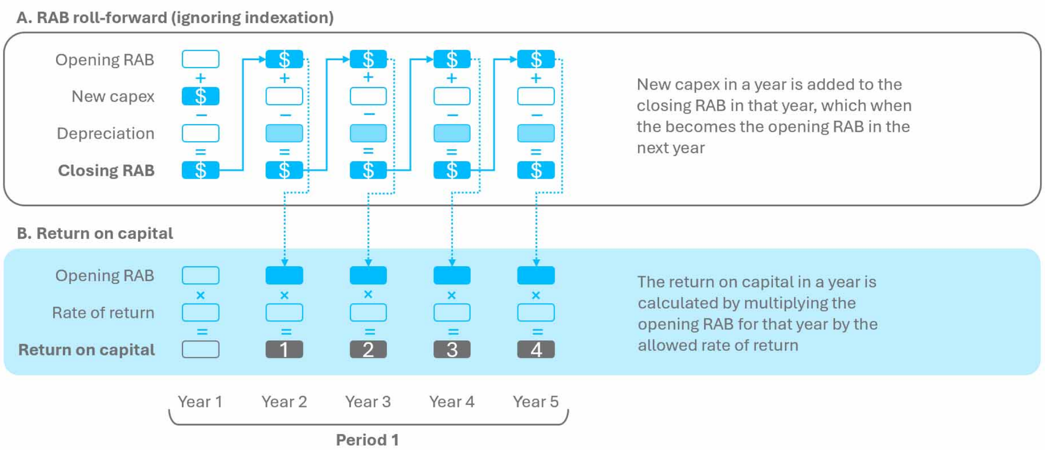
If there is no CESS

A capital expenditure saving reduces the amount added to the regulatory asset base (RAB). Consumers therefore ultimately benefit from the saving through lower future revenues. However, absent a CESS, the benefit retained by the network business depends on when the saving occurs.

To illustrate this, let's start with how the return on capital is derived over a regulatory period. *Figure 1* below is split into two calculations. The top calculation (inside the grey box) shows how the RAB is rolled forward from one year to the next. In this example, it shows how forecast capex in year 1 flows into the closing RAB for that year and then on to the opening and closing RAB values for subsequent years over that period. The bottom calculation (inside the shaded blue box) shows how the opening RAB for a given year is multiplied by the rate of return to derive the return on capital for that year.

In this example, a saving achieved in Year 1 allows the network business to retain four years of forecast return on capital before the next regulatory period (this benefit is reflected in the solid grey boxes marked 1 to 4).

Figure 1: Deriving the return on capital



Note: For simplicity, the figure ignores indexation, depreciation and mid-year timing of capex.

113 AEMC, Economic regulation of network service providers, November 2012, p. vi. The ex post review (discussed further in Chapter 4) was also introduced at this time as a complementary measure to address these concerns.

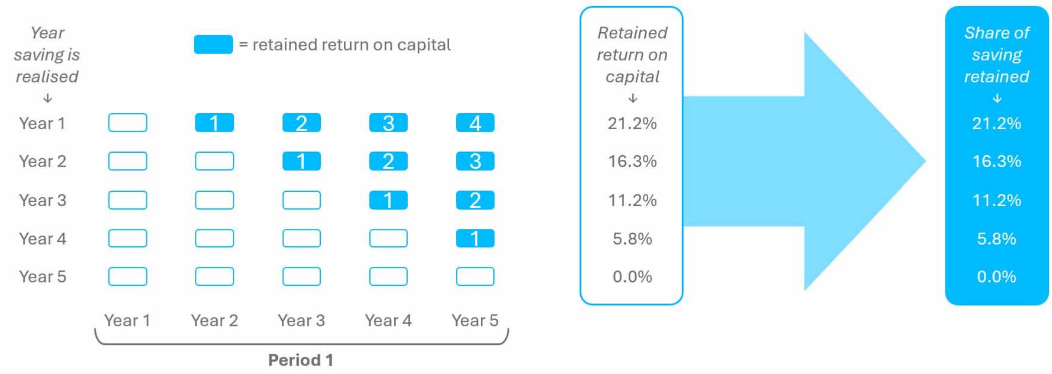
114 AER, Capital expenditure incentive guideline for electricity network service providers, Explanatory statement, November 2013, p. 19.

Once the return on capital allowances are set for a regulatory period, a network business can retain those allowances even if actual capital expenditure differs from that allowed. In this way, if a network business realises a saving in year 1 (i.e., actual spend is lower than the allowance), then it can retain the associated return on capital for years 2 to 5 (i.e., 4 years). If the saving is realised in year 2, then the return on capital is retained for years 3 to 5 (i.e., 3 years), and so on. A saving achieved in year 5 is immediately reflected in the lower opening RAB for the next period, meaning that no benefit is retained by the network business.

The graduated retention is illustrated in *Figure 2* with the solid blue squares indicating the number of years that a network business retains the return on capital for. It shows how the number of retained years drops from 4 if the saving is realised in year 1 down to zero if realised in year 5.

As with the EBSS, the period of retention also translates into a *share* of retention (in per cent terms), which measures the share of the initial saving that is retained by the network business in present value terms. For a given rate of return, the share increases the longer the return on capital is retained for and vice versa. To illustrate, *Figure 2* shows how the period of retention translates into a retained return on capital (inside the blue box), which is the present value of the retained return on capital divided by the saving. That retained return on capital then becomes the share of saving retained (in the solid blue box).

Figure 2: how retained share of savings varies without a CESS



Note: The present value of retained financing costs, as a share of the saving, can be calculated using the following simplified formula, where 'N' is the number of years retained and 'R' is the rate of return: t=1NR1+Rt. The formula is simplified because it assumes the same rate of return each year. A rate of return of 6.1 per cent was used to align with the discount rate used in the EBSS example.

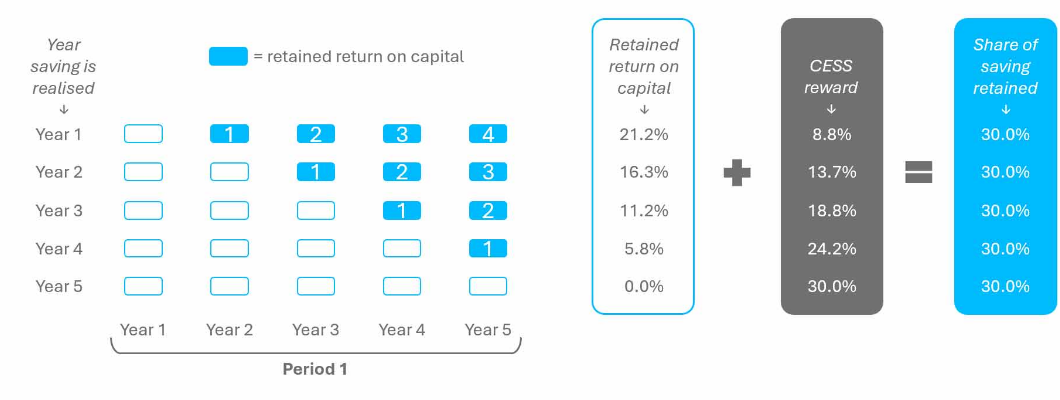
Without a CESS, network businesses face different incentives to realise capital expenditure savings across the regulatory period, with the strongest incentive in year 1 of the period and weakest in year 5.

If there is a CESS

The CESS was introduced to increase and levelise the incentive for efficient capital expenditure and the oversight of capital expenditure that exceeds allowances. Prior to the introduction of the CESS and ex-post review in 2012, all actual capital expenditure was added to the RAB at the next regulatory reset without any other adjustments. This created a potential incentive for the network business to increase its capital expenditure so that it will earn a return on that expenditure in the next regulatory period.

The CESS provides an additional reward that tops up the benefit retained by the network business where capital expenditure is less than the allowance, and creates a penalty if expenditure exceeds the allowance. This is illustrated in *Figure 3*. The CESS reward (in the grey box) is backsolved so that the network business retains approximately the same share of efficiency benefits regardless of when the saving occurs. Historically, this share was set at 30 per cent, consistent with the incentive strength produced by the EBSS (for a given discount rate).

Figure 3: How retained share of saving is increased and levelised with a CESS



Although the illustrations above refer to savings, the same logic applies equally to overspends. With a CESS, the network business will receive a CESS penalty that once added to financing costs incurred without a return on capital allowance equates to a cost equivalent to 30 per cent of the overspend in present value terms.

Source: AEMC

This declining incentive also had the potential to distort:[115]

- an NSP's decision about whether to undertake capex or opex, because incentives for efficient opex are more balanced over time (due to the EBSS) whereas they decline for capex
- capex towards the end of the regulatory control period when the benefits of reduced expenditure are the weakest.

The CESS was designed to ensure networks face a consistent, predictable and symmetrical financial incentive to realise capital underspends and avoid overspends, complementing the EBSS.

The CESS applies a 70:30 sharing ratio between consumers and NSPs, with some exceptions

The CESS applies a 70:30 sharing ratio between consumers and NSPs for an overspend, meaning that NSPs bear a 30 per cent share of the costs of spending more than their capex allowance.[116] In relation to underspends a tiered sharing ratio applies:[117] a 70:30 sharing ratio is applied to underspends of up to 10 per cent of the capex allowance and a 80:20 sharing ratio for underspends exceeding 10 per cent.[118] CESS benefits or penalties are provided for in the next regulatory control period.

The tiered sharing ratio for underspends was introduced following the AER's 2023 *Review of networks incentive schemes*. This was in recognition that capex is often less recurrent and harder to accurately forecast, increasing the potential for underspends of the allowance to result from factors other than genuine efficiency gains.[119]

115 AER, [Capital expenditure incentive guideline for electricity network service providers, Explanatory statement](), November 2013, pp. 24-25.

116 This ratio was approximately equivalent to the sharing ratio under the EBSS at the time the CESS was introduced.

117 Noting this ratio does not yet apply to some NSPs whose revenue determinations were finalised prior to the AER's change in methodology, i.e. prior to the AER's 2023 *Review of networks incentive schemes*.

118 AER, Capital expenditure incentive guidelines, August 2025.

119 AER, Review of incentives schemes for networks, Final decision, April 2023, p. 15.

The AER also updated its *Capital Expenditure Guideline* in 2025 and made amendments to the application of the CESS, including:[120]

- DNSPs are able to propose a volumetric adjustment per connection type to ensure DNSPs are not rewarded or penalised under the CESS for changes in capex for changes in the volume of connections, which it cannot control.
- DNSPs are able to seek ex post reductions in CESS penalties for large bespoke connections that are not in the original forecasts, such as data centres.
- TNSPs are able to:
    - seek ex post reductions in CESS penalties where the scope of works increased for both ISP projects and non-ISP projects for reasons that are genuinely beyond the TNSPs control and unforeseeable, or propose variations to the application of the CESS for specific ISP projects
    - remove CESS rewards for abandoned ISP projects, and
    - propose variations to the application of the CESS (for businesses with a single asset in their RAB).

Capex reduced following introduction of the CESS, with a return to growth in recent years

The AER concluded in its 2023 *Review of incentives schemes for networks* that forecast and actual capex had declined by around 50 per cent since around the time the CESS had been introduced (between 2012-2021). It noted that underspend relative to forecasts had also declined, indicating that the accuracy of forecasts had improved over time across distribution and transmission. The AER also noted that for DNSPs, the average underspend has fallen from around 18 per cent in the first regulatory control period to around 7 per cent at that time.[121]

Since then, capex requirements have grown, especially for TNSPs (see Figure 3.5 and Figure 3.6). Key drivers for DNSPs capex growth included replacing ageing network infrastructure, expenditure relating to CER integration and servicing growth in demand and connections from electrification. The key driver for TNSPs' capex growth was related to large transmission projects identified under AEMO's ISP, with ISP projects accounting for 45 per cent of TNSP capex between 2021-2024.[122,123]

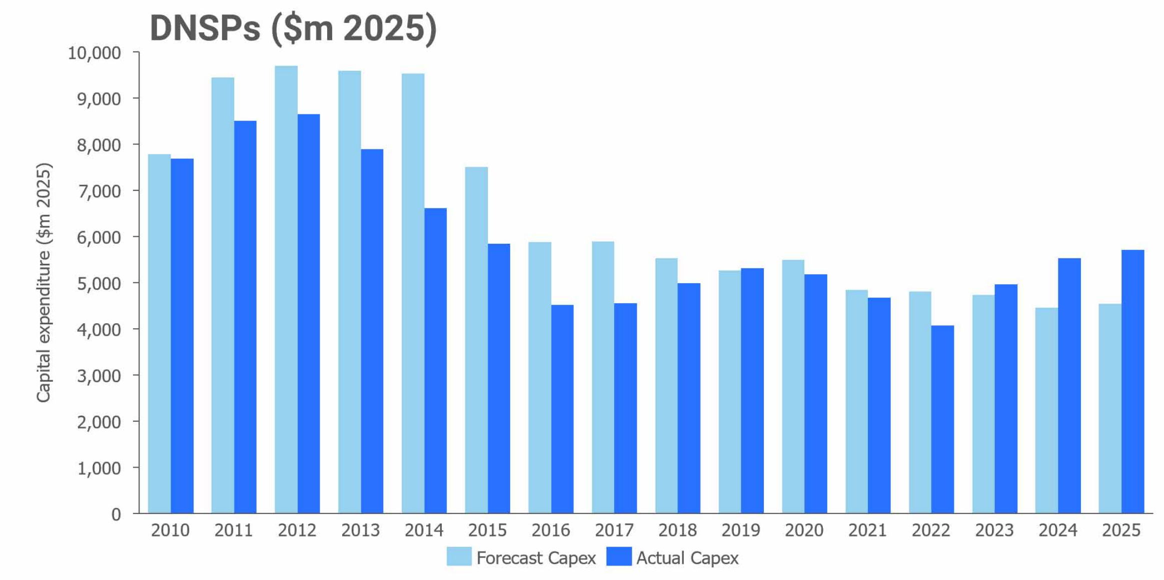
120 AER, *Capital expenditure incentive guideline review, Explanatory statement – Final guidelines*, August 2025.

121 AER, *Review of incentives schemes for networks, Final decision,* April 2023, p. 18.

122 AER, *Electricity and gas networks performance report 2025*, December 2025, p. 26.

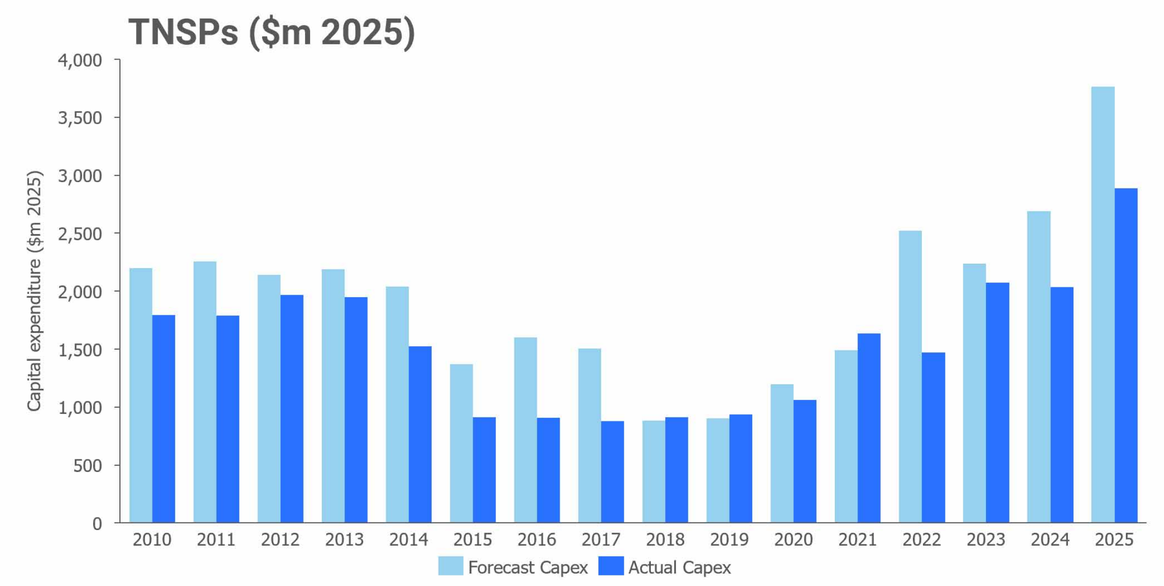
123 AER, *Electricity and gas networks performance report,* 2026, p. 25.

Figure 3.5: Forecast and actual electricity capital expenditure by year - DNSPs ($m real 2025)



Source: AEMC, based on data provided by the AER

Figure 3.6: Forecast and actual electricity capital expenditure by year - TNSPs ($m real 2025)



Source: AEMC, based on data provided by the AER

3.2.4 The Demand Management Innovation Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM)

The AEMC introduced the DMIS to incentivise DNSPs to pursue NNOs

The AEMC introduced the DMIS in its current form in 2015 to address a perceived structural bias in the framework for NSPs to pursue network solutions over NNOs.[124] Concerns raised at the time included that NSPs may under-invest in NNOs because any benefits are short term relative to the regulated rate of return earned on (capex-based) network investment, that DNSPs do not capture the benefits achieved at other levels of the supply chain (such as reduced generation costs) and that the measures at the time to promote NNOs were widely considered ineffectual.[125]

The DMIS was therefore introduced with the objective of providing DNSPs with an incentive to undertake efficienct expenditure on relevant NNOs related to demand management. 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 caped 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. [126]

Up to and including FY2024, the DMIS had resulted in an estimated $52 million in benefits to consumers, at a cost of approximately $3.5 million.[127]

The DMIAM is a complementary innovation allowance for NNOs

The DMIAM is a research and development fund to support the development of innovative ways of using demand management. Its objective is to provide distribution businesses with funding for research and development in demand management projects that have the potential to reduce long term network costs. It was introduced for DNSPs in 2017 as a complementary mechanism to the DMIS, and extended to TNSPs in 2021.

The DMIAM was introduced in recognition that regulated monopolies like DNSPs have less incentive to conduct research and development than competitive businesses. This is because all else equal they face less upside but still face downside risk related to innovation.[128] Incentives for innovation are discussed in more detail in section 3.6.

The DMIAM provides each distribution network with an ex-ante annual allowance for research and development into innovative demand management projects, comprising a fixed component of $200,000 ($2017 dollars, indexed for inflation) plus 0.075 per cent of the annual revenue requirement for DNSPs, and 0.1 per cent for TNSPs.

In FY2025 the AER approved DMIAM expenditure of $9.87 million.[129]

3.2.5 The Service Target Performance Incentive Scheme

The STPIS seeks to provide NSPs with financial incentives to maintain and improve network reliability and performance to the extent that customers are willing to pay for it. Under the STPIS, NSPs are rewarded for outperforming against service performance targets and penalised for

124 AEMC, *Demand management incentive scheme*, August 2015.

125 AEMC, *Demand management incentive scheme rule change, Consultation paper,* February 2015, p. 10.

126 AER, *Explanatory statement, Demand management incentive scheme*, Electricity distribution network service providers, December 2017

127 AER, *State of the energy market*, 2025, p. 105.

128 AER, *Demand management innovation allowance mechanism, Electricity distribution network service providers, Explanatory statement*, January 2026, p. 9.

129 AER, *Demand management innovation allowance mechanism assessment 2024-25*, April 2023.

underperforming against these targets. The STPIS complements the EBSS and the CESS by ensuring that cost reductions in opex and capex do not come at the expense of service levels to customers.[130]

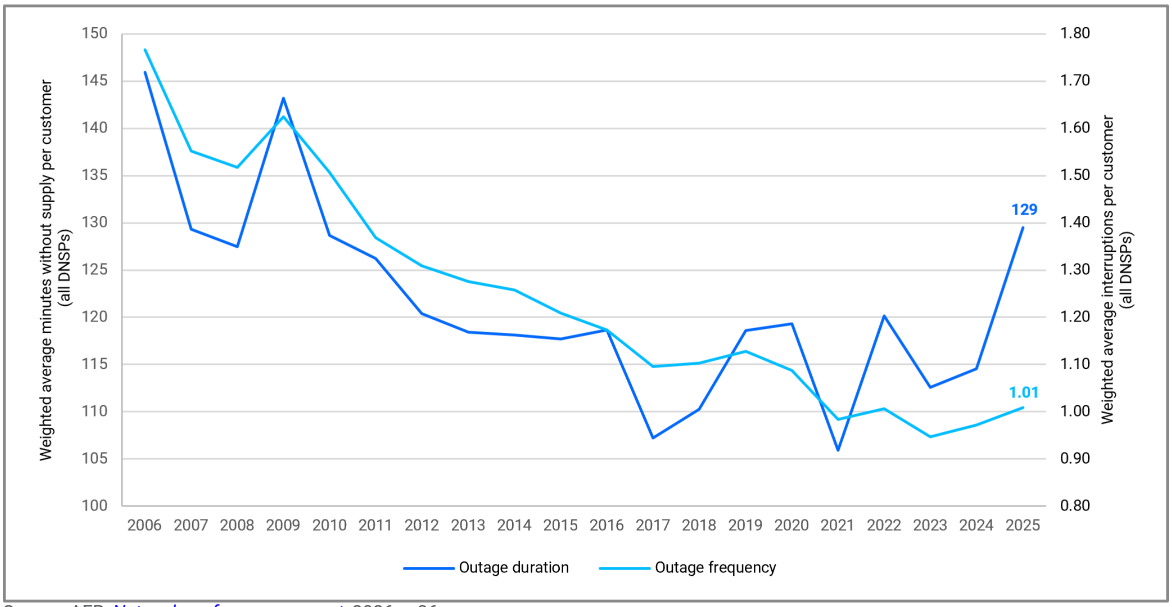
The distribution STPIS has produced positive outcomes for consumers

For electricity DNSPs, the STPIS covers frequency and duration of interruptions to supply as measured by the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). Reliability targets are based on average historical levels of reliability and updated every 5 years as part of the regulatory reset process. Targets are also informed by the value that customers place on reliability which are also assessed by the AER every 5 years.[131]

The AER reviewed the DNSP STPIS as part of its incentives review in 2023. The AER's overall assessment was that the DNSP STPIS had been successful in reducing the number and duration of distribution outages. The AER noted that the average number of interruptions per customer per year had declined by 38 per cent between 2006 and 2020. Similarly, the average duration of outages reduced by 26 minutes over the same period. [132]

Figure 3.7 below illustrates current average frequency and duration of DNSP interruption trends from 2006 to 2025. These demonstrate a general improvement in interruption performance since 2006, with the recent increase in interruption duration in 2025 attributable to interruptions in the Ergon and AusNet regional distribution areas.

Figure 3.7: DNSP reliability performance has improved since 2006



Source: AER, *Network performance report*, 2026, p 36.

130 AER, *Review of incentives schemes for networks, Final decision,* April 2023, p. 23.

131 AER, *Review of incentives schemes for networks, Final decision,* April 2023, p. 23.

132 AER, *Review of incentives schemes for networks, Final decision,* April 2023, p. 26-27.

The transmission STPIS operates differently, with three separate components

For TNSPs, the STPIS has three components:

- A Market Impact Component (MIC)
- A Network Capability Component (NCC), and
- A Service Component.

The **MIC** provides an incentive to TNSPs to minimise the impact of planned and unplanned transmission outages that affect wholesale market outcomes. The AER introduced this component because TNSPs often scheduled planned outages at times of high demand when the outage could cause significant financial impact for generators or market participants.[133] However, the AER suspended the MIC in April 2025 due to changes underway in the system having an impact the AER's ability to use historic performance measures as an accurate indicator of future performance.[134] The AER has convened a working group to develop an alternative to the MIC, which is expected to report its findings to the AER by the end of the year.

The **NCC** provides incentive payments to TNSPs to undertake small, high net benefit projects that reveal the capability of parts of its existing network and which identify and implement measures that would provide greater value to generators and consumers.[135] The AER estimates that consumers have funded around $180 million in expenditure across the TNSPs, delivering around 100 projects. In its 2025 review of the transmission STPIS the AER decided to retain the network capability component with minor amendments to improve its operation.[136]

The **Service Component** of the transmission STPIS provides incentives for a TNSP to maintain the reliability of its network. It does this by providing a reward or penalty of ± 1.25 per cent of annual revenue, based on the number of unplanned network outages and how quickly these outages are restored.[137] As part of its 2025 review of the transmission STPIS, the AER determined that the service component should remain with minor amendments.

3.2.6 The ESIS and CSIS are small scale incentive schemes established by the AER

Under the NER, the AER has powers to establish small-scale incentive schemes that apply to DNSPs.[138] The aggregate incentive is limited to no more than 0.5 per cent of the annual revenue requirement for a DNSP, or 1 per cent with the DNSP's consent.

The AER has established the following schemes under these provisions:

1. the **export service incentive scheme**
2. the **customer service incentive scheme**

The export service incentive scheme

The AER established the export service incentive scheme (ESIS) in 2023. The ESIS enables the AER to set targets for DNSP export service performance and require DNSPs to report on

133 AER, *Review of incentives schemes for networks, Final decision,*April 2023, p. 23.

134 AER, *Electricity transmission Service Providers, Service target performance scheme, Final amendments, Explanatory statement,* April 2025, p. 2.

135 AER, *Electricity transmission service providers, Service target performance incentive scheme, Final amendments, Explanatory statement*, April 2025, p. 19.

136 AER,*Electricity transmission service providers, Service target performance incentive scheme, Final amendments, Explanatory statement*, April 2025, p. 3.

137 AER, *Electricity transmission service providers, Service target performance incentive scheme, Final amendments, Explanatory statement*, April 2025, p. 25.

138 NER clause 6.6.4.

performance against those targets. Under the ESIS, DNSPs may be financially rewarded or penalised depending on how they perform against their export service targets.[139]

The ESIS was in recognition that DNSPs may face incentives to reduce network expenditure at the expense of export service quality. While the STPIS incentivises import service performance, it does not include measures related to the provision of export services, such as the frequency and volume of export curtailment. The ESIS therefore was introduced to complement the STPIS and create balanced incentives for DNSPs to provide both import *and* export services at a level of service quality in line with what consumers value. [140]

At this time, the AER has not yet applied the export service scheme to any DNSPs.

Customer service incentive scheme

In 2020, the AER established the CSIS which is designed to encourage electricity distributors to engage with their customers and provide customer service in accordance with their preferences.[141]

The CSIS allows the AER to set targets for distributor customer service performance with DNSPs being financially rewarded or penalised depending on how they perform against these targets. The AER has established the CSIS as a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a distributor's customers.[142] The flexibility is intended to allow for the evolution of customer engagement and adapt to the introduction of new technologies. The CSIS is also intended to create an incentive for distributors to maintain and improve customer services not covered by the STPIS, or other mechanisms, when desired by customers.[143]

Under the scheme, DNSPs may design the scheme as part of their regulatory proposal based on customer preferences. The AER assesses the scheme against principles specified in its CSIS guidance governing components such as performance targets and parameters including the requirement that the performance parameters must be an aspect of customer experience that is within the substantial control of the DNSP. [144]

The CSIS was applied by the AER to the following determinations:

- Victorian DNSPs for the 2021-26 regulatory control period (CitiPower, Powercor, Jemena, AusNet Services, United Energy).
- NSW and Tasmanian 2024-29 regulatory control period (Ausgrid, Endeavour Energy, Essential Energy and TasNetworks).

  However, the scheme was subsequently not applied in the most recent 2026-31 revenue determinations due to concerns around data quality, overlap with the STPIS, and other compliance requirements.[145]

139 AER, *Export service incentive scheme, Explanatory statement*, June 2023.
140 AER, *Incentivising and measuring export service performance, Final report*, March 2023, p. 11.
141 AER, *Explanatory statement customer service incentive scheme*, July 2020.
142 AER, *Explanatory statement customer service incentive scheme*, July 2020.
143 AER, *Explanatory statement customer service incentive scheme*, July 2020.
144 AER, *Final customer service incentive scheme*, July 2020.
145 AER, *Powercor electricity distribution determination (1 July 2026 to 30 June 2031), Final decision*, April 2026, p. x.

3.3 We propose to explore the incentives for NSPs to invest in capex relative to opex

The potential for NSPs to preference capex-based solutions over opex-based solutions is a long-standing concern with the regulatory framework, and there are likely a range of reasons that could lead to such a preference. This is of growing concern because NNOs, such as using coordinated CER to provide network services, are often treated as opex under the regulatory framework. As the viability of NNOs increases, the impact on consumer outcomes from any such preference will grow.

3.3.1 There are a range of factors that may lead NSPs to preference capex over opex

The Commission explored whether the regulatory framework may create incentives for NSPs to have a preference for capex over opex in our 2018 *Electricity network economic regulatory frameworks (ENERF)* review and engaged Cambridge Economic Policy Associates (CEPA) to undertake a detailed review.[146] This section summarises the reasons that NSPs may exhibit a preference for capex-based solutions, building on this previous work undertaken as well as issues recently raised by stakeholders with the AEMC. For a more detailed discussion please see the CEPA (2018) report.

The key reasons that may impact an NSP's preferences for capex relative to opex[147] that have been identified and which we discuss below are:

1. **Financial factors**
    a. Differences in the regulated rate of return and NSPs' actual financing costs
    b. The impact of the regulated rate of return on the sharing ratios between the CESS and the EBSS
    c. Interactions between the CESS and the EBSS for shorter asset life investments.
2. **Non-financial factors**
    a. Investor preferences for long-term, stable returns
    b. Perceived or actual risk associated with NNOs relative to network solutions.

The impact of the regulated rate of return compared to actual NSP financing costs

Differences between the regulated rate of return and an NSP's actual cost of capital can distort its incentives when choosing between capex and opex.[148] Where an NSP must deliver an outcome and can choose between capex-based or opex-based options:

- If the regulated rate of return is higher than the NSP's cost of capital, the NSP will have a financial incentive to favour the capex-based solution.
- Conversely, if the regulated rate of return is lower than the NSP's cost of capital, the NSP will have a financial incentive to favour the opex-based solution.

An NSP's cost of capital changes over time and cannot be directly observed. It reflects the returns required by the debt and equity investors that finance the business.

146 CEPA, *Expenditure incentives faced by network service providers, Final report*, 25 May 2018.

147 We also note that in some cases there may be incentives for NSPs to prefer opex over capex, such as in cases where the regulated rate of return is below an NSPs actual financing costs or where an NSP faces balance sheet pressure and cannot further increase its debt levels.

148 Harvey Averch and Leland L. Johnson, 'Behavior of the Firm Under Regulatory Constraint', *American Economic Review*, 52(5), December 1962, 1052–1069.

To illustrate, consider an NSP with a cost of capital of 5 per cent. It can deliver the same service either by investing $100 in a capex asset or by incurring $5 of opex each year.[149]

- **If the regulated rate of return is 6 per cent**, the capital asset costs the NSP $5 each year to finance, while its regulated revenue increases by $6. This produces an annual financing margin of $1. By comparison, the NSP recovers the $5 of opex at cost, leaving it in a financially neutral position. The NSP therefore has a financial incentive to choose the capex solution.
- **If the regulated rate of return is 4 per cent**, the capital asset still costs the NSP $5 each year to finance, but its regulated revenue increases by only $4. This produces an annual financing shortfall of $1. By comparison, the NSP recovers the $5 of operating expenditure at cost. The NSP therefore has a financial incentive to choose the opex solution.

Although the two options deliver the same service at the same underlying economic cost, differences between the regulated rate of return and the NSP's cost of capital can distort its choice between them.

In our 2018 ENERF review we concluded that:

'Where an NSP expects to be able to source funds at a rate lower than the regulated rate of return, analysis indicates that the current framework always provides a strong bias towards capex solutions, and that bias is the strongest for capex solutions that have a long expected asset life (e.g. a traditional network poles and wires solution). The Commission considers this has significant implications for the evolution of the electricity sector, especially in a future where there are a variety of solutions to a given network problem'.[150]

Differences in sharing ratios between the EBSS and CESS, which vary over time

A second financial factor influencing the potential for incentives to spend on capex or opex is the difference in sharing ratios across the EBSS and CESS. As outlined earlier in this chapter, the sharing ratio under the CESS is 70:30 between consumers and NSPs (with some exceptions), while the exact sharing ratio under the EBSS depends on the NSP's internal discount rate. The AER noted that in 2020 that the effective sharing ratio at the time was closer to 80:20 between consumers and NSPs. More recently the sharing ratio has returned closer to 70:30.[151]

Where there is an imbalance between the sharing ratios it may distort incentives to chose between capex and opex and may encourage cost shifting from opex to capex or increasing management effort to cut capex compared to opex.[152] The impact of this effect depends on the sharing ratio of the EBSS, which is determined by an NSP's internal discount rate and varies over time.

Interactions between the CESS and EBSS for short asset lives

A third financial factor is an imbalance between the CESS and the EBSS when an opex solution is short-term and does not continue in perpetuity. This may include cases where an NNO is used to defer a capex solution.

CEPA's (2018) analysis found that the financial incentive to undertake opex decreases with asset life. Figure 3.8 shows the net present value of an opex investment relative to a capex investment, by asset life. A ratio of less than 1.0 indicates the net present value of the opex investment is less

149 For simplicity, this illustration assumes that the asset does not depreciate, the operating expenditure continues indefinitely, the full capital expenditure enters the regulatory asset base, and tax and other adjustments are ignored. At a cost of capital of 5 per cent, both options have the same present value.

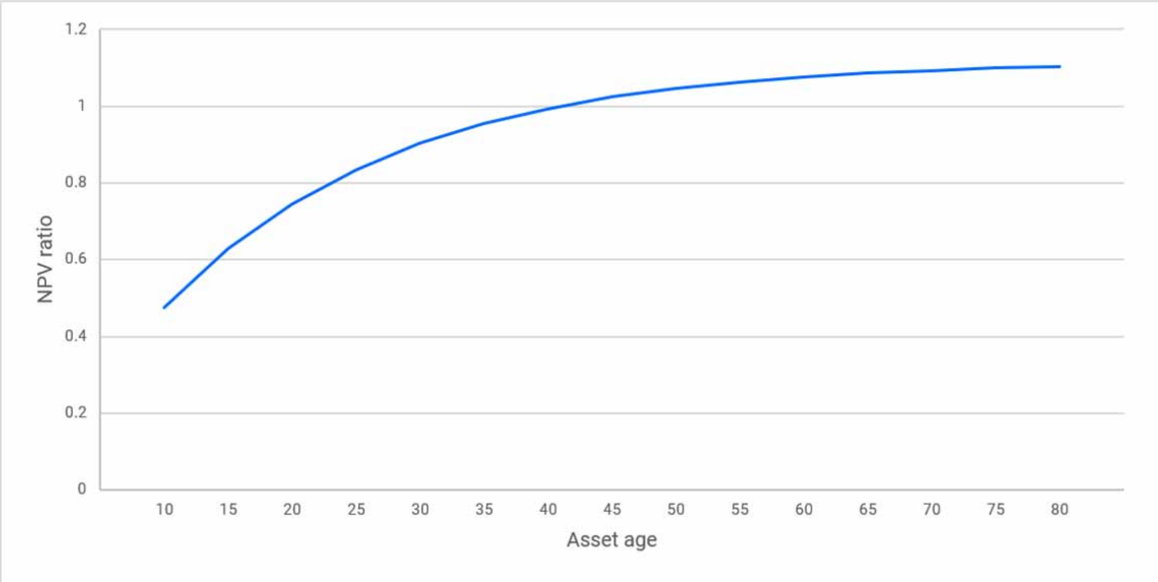
150 AEMC, *Economic regulatory framework review*, July 2018, p. viii.

151 AER, *Review of incentives schemes for networks, Final decision*, April 2023. Applying current discount rates to the scheme's six-year retention period suggests that the effective present-value sharing ratio is now closer to 70:30.

152 AER, *Review of incentives schemes for networks, Final decision,* April 2023, p. 13.

than that of the equivalent capex investment. This analysis found that the net present value of capex and opex are relatively balanced at an asset life of 40 years, but decline for opex as asset life reduces.

Figure 3.8: NPV ratio of opex vs capex investment, based on asset life



Source: CEPA, *Expenditure incentives faced by network service providers, Final report*, May 2018.

This effect is largely a result of the fact that the CESS and EBSS consider costs and benefits over different time periods. The CESS does not consider the costs and benefits that will be faced when the asset reaches the end of its life. The EBSS, on the other hand, shares efficiency gains in perpetuity. The EBSS provides NSPs with a large upfront benefit/penalty (ie the first six years), with consumers then bearing the benefit/penalty after that into perpetuity.

As an example, consider a scenario where an NSP chooses between a 5 year capex option or opex option to address a network need. If it chooses the capex option, the CESS will penalise the NSP 30 per cent of 5 years worth of costs (compared to not incurring any capex). Provided the capex option is efficient, a capex allowance will be made in a future revenue determination when the asset needs replacing at the end of its life. If the NSP instead chooses the opex option it needs to pay for 100 per cent of the costs for 6 years. In this scenario it has a strong incentive to adopt the capex option.

In the case of long-lived asset (e.g. a 50 year asset) the CESS would penalise the NSP 30 per cent of 50 years worth of costs. This would not be materially different to 30 per cent of the costs in perpetuity under the EBSS. This results in a relatively balanced incentive for long lived assets.

These outcomes are illustrated in worked examples in CEPA (2018).[153]

Investor preferences for long-term, stable returns

In addition to the financial factors noted above, NSPs may still exhibit a preference for capex solutions over opex solutions if there is an investor preference for long-term, stable returns.[154] Under the regulatory framework capex is capitalised into the RAB, which provides an NSP with

153 See examples 1-3 in CEPA, *Expenditure incentives faced by network service providers, Final report,* 25 May 2018, p. 49-51.

154 CEPA, *Expenditure incentives faced by network service providers, Final report,* 25 May 2018, p. 62.

long-dated cost recovery over the life of the network asset at a regulated rate of return. By contrast, opex is recovered at the time it is forecast to occur and therefore does not earn a return.

CEPA (2018) reviewed qualitative evidence for such a preference, including investment analyst coverage of Australian and international electricity networks, and concluded that the evidence available indicated that investors are 'comfortable' with the long-term stable returns associated with a RAB-based approach under the regulatory framework.[155]

CEPA also concluded that to the extent that investors have a preference for these financial outcomes, they may provide incentives for management to deliver outcomes aligned with their preferences.[156] This could influence internal processes for capital projects such as clearer approval pathways, or prioritisation based on the long-term revenue implications of capital assets being included in the RAB. By contrast, operational expenditure may be more exposed to organisational cost scrutiny, annual budget pressure and productivity expectations, particularly given the incentives created through the EBSS and benchmarking frameworks.

Greater perceived or actual risk associated with NNOs

Investing in an opex-based solution poses at least two additional potential risks for an NSP, relative to a capex-based network solution:

1. Regulatory cost recovery risk
2. Operational risk.

Regulatory cost recovery risk

Under the current framework, NSPs are likely to have greater cost recover certainty for long-term network solutions that are capex based compared to those that are opex based. Once capex is incurred it is rolled into the RAB and no future review is conducted (subject to CESS penalties and a one off ex post review in some cases). However, opex may be more subject to reassessment by the AER at each revenue determination period or through pass through application processes.[157]

This dynamic can create greater cost recovery uncertainty for opex relative to capex. The AEMC has made rule changes in recent years to address this uncertainty for TNSPs using NNOs as an alternative to network augmentation or for system security, but this regulatory uncertainty may remain to an extent for DNSPs.[158]

Operational risk

In many cases NNOs are relatively new applications of technology to provide network services. NSPs may have less experience using these types of solutions and they may involve higher operational complexity and risk.

NNOs that involve contracts with external service providers are unlikely to provide the same level of control or assurance of delivery that is associated with direct ownership and control of a physical infrastructure asset.[159] Compared to an in-house opex or capex solution, these arrangements may provide less control over the service, and less certainty that the solution will perform as required, when required.[160] This performance consideration could be highly

155 CEPA, *Expenditure incentives faced by network service providers, Final report,* 25 May 2018, p. 64.

156 CEPA, *Expenditure incentives faced by network service providers, Final report,* 25 May 2018.

157 AEMC, *Electricity network economic regulatory framework review, Final report,* July 2018, p. 32.

158 See: AEMC, *Improving the cost recovery arrangements for transmission non-network options, Final determination*, March 2025 and AEMC, *Improving security frameworks for the energy transition, Final determination*, March 2024.

159 AEMC, *Economic network economic regulatory framework review, Final report,* July 2018, p. 32.

160 CEPA, *Expenditure incentives faced by network service providers, Final report,* 25 May 2018 p. 65.

consequential for NSPs given the strength of rewards and penalties related to service reliability created by the STPIS.

These arrangements may also result in greater risks associated with negotiating and managing a relationship with the third party, compared to a solution provided in-house - for example in managing disputes, performance, or insolvency.[161]

3.3.2 Other features of the regulatory framework seek to support the uptake of NNOs

Two of the key mechanisms in the current regulatory framework seek to provide more balanced outcomes between network and non-network options :

- the financial incentives under the DMIS, and
- the procedural requirements in the RIT-T and RIT-D.

The impacts of the DMIS

DNSPs can access incentive rewards for 'demand management' initiatives (ie NNOs) through the DMIS. However, the payments available under the DMIS are relatively constrained - capped at 1 per cent of the DNSPs' allowed revenue for that year.

Uptake of the DMIS has also been low. Total incentive payments under the scheme were just $3.5 million over the five years from FY2020 - FY2024.[162] This is relative to over $433 million in incentive payments potentially available to DNSPs under the DMIS over this time.[163]

Stakeholders have raised barriers to uptake of the DMIS including scope restrictions and the administrative burden to secure rewards under the scheme on a project by project basis. The scheme also only applies to DNSPs and so does not support NNOs at the transmission level.[164]

Consideration of non-network options under the RIT-T and RIT-D

Under the current rules, DNSPs are required to consider NNOs when undertaking a RIT-D, including the publication of a non-network options report that provides an assessment of credible non-network and network options to address an identified need. For transmission, TNSPs are required to assess all credible options when undertaking the RIT-T, which includes non-network options.

While the RIT-D and RIT-T require the consideration of non-network options, there are relatively few examples where this has led to NSPs preferring non-network options over capital-based options.[165]

Part of the intended procedural operation of the RIT-D and RIT-T is the requirement for NSPs to explain publicly what the need is and their preferred solution to provide non-network alternative providers an opportunity to challenge proposed network solutions where non-network options exist and could be more efficient. However, the limited number of projects that adopt a non-network option suggest that this may not be sufficient without additional measures.

161 CEPA, *Expenditure incentives faced by network service providers, Final report,* 25 May 2018, p. 65.

162 AER, *State of the energy market ,* 2025, p.105.

163 Source: AEMC analysis based on data provided by the AER.

164 The Commission decided against extending the DMIS to TNSPs in 2019 given TNSPs already have obligations to consider NNOs under the RIT-T and, utilmately, it was not satisfied the benefits would outweigh the costs to consumers. See: AEMC, Demand managment incentive scheme and innovation allowance for TNSPs, Final determination, December 2019, pp. i-ii.

165 AEMC, *Improving the cost recovery arrangements for transmission non-network options, Consultation paper,* August 2024, p. i.

International approaches to addressing capex and opex incentives

The Commission previously reviewed international approaches to addressing a potential capex bias and engaged Frontier Economics in 2017 to explore a 'totex' approach to network expenditure. A totex approach treats opex and capex together as total expenditure (totex) and enables more equivalent regulatory treatment of capex and opex. Frontier reviewed the implementation of totex approaches in other jurisdictions, noting that at the time it was 'generally accepted' that the shift to a totex scheme in the UK's electricity sector had been successful in removing incentives to preference capex over opex.[166] Frontier was not engaged to make a recommendation as to the desirability of introducing totex in the NEM framework, but noted that this would be a non-trivial change and estimated it would take around 2-3 years to implement.[167]

Box 7 below provides a case study on Ofgem's application of a totex framework in Great Britain.

Box 7: What is a 'totex' approach and how does it change network regulation? An Ofgem case study

When Ofgem examined the interactions of capex and opex, it identified that the different regulatory treatment of capex and opex could distort networks' expenditure choices. Capitalised expenditure entered the regulatory asset base and earned a return over time, while opex was immediately expensed and was historically subject to different incentive and cost-assessment arrangements. In Ofgem's terminology, expenditure recovered immediately is 'fast money', while expenditure added to the regulatory asset base and recovered over a longer period is 'slow money'. Ofgem identified two forms that **capitalisation bias** could take:[1]

- accounting substitution - classifying expenditure as capex rather than opex, without changing the underlying activity, to obtain a more favourable regulatory outcome
- physical substitution - choosing a more capital-intensive solution even where an opex-based solution would have a lower total cost.

A totex approach seeks to reduce these distortions by treating capex and opex together. Once the regulator has determined an efficient total expenditure allowance and the outputs the network must deliver, the network is not locked into the capex–opex mix forecast at the start of the price control. As circumstances, information and technologies change, it can re-calibrate how it delivers those outputs.

Because the regulatory incentive and capitalisation treatment do not depend on the decision the network makes, the network is incentivised to find the most efficient (least cost) way to meet its obligations, rather than by shifting expenditure into the category receiving more preferable regulatory treatment. This gives the network substantial freedom to make delivery decisions during the price-control period, while the regulator protects consumers through the overall allowance, output requirements, incentives and expenditure scrutiny.[2]

In broad terms, a totex approach involves three related changes to regulatory methodology:

1. **Cost assessment** - assessing the efficient level of total expenditure, rather than relying on separate assessments of capex and opex
2. **Incentives** - applying a common incentive or sharing rate to expenditure performance, regardless of whether an underspend or overspend relates to capex or opex
3. **Cost recovery** - applying a predetermined split to totex, with one proportion recovered as fast money and the remainder added to the regulatory asset value as slow money. This is called the

166 Frontier Economics, *Total expenditure frameworks,* December 2027, p. vi.

167 Frontier Economics, *Total expenditure frameworks*, December 2017, p. ix-x.

‘capitalisation rate’. The timing of recovery therefore no longer depends directly on whether the network records the expenditure as capex or opex

Totex can encourage innovation, focus networks on whole-of-life value and reduce disputes about the boundary between capex and opex. Ofgem cited changes to the delivery of the gas mains replacement program during the eight-year 2013–21 price control as an example: networks used online inspections, remote repairs and advanced leakage management to repair some mains rather than automatically replacing them, with an estimated reduction in costs to consumers of around £2 billion without compromising safety.[3]

However, a totex approach may not address every potential source of capitalisation bias. Cultural or engineering preferences for building assets, reputational concerns, risk aversion and ownership expectations may continue to influence decisions and may require complementary regulatory measures.[4]

[1] Frontier economics, *Total expenditure frameworks report* , 2017, p. 35.
[2] Frontier economics, *Total expenditure frameworks report* , 2017, p. vi.
[3] Energy Networks Australia, *Abolising acronyms: a Totex approach*, November 2017.
[4] Frontier economics, *Total expenditure frameworks report* , 2017, p. vii.

3.3.3 We propose to explore reforms that could better levelise incentives between capex and opex

We propose to explore the following areas further:

- **Which factors matter most in driving any capex bias.** There are several possible causes of an imbalance in incentives, which we have set out above. We propose to examine these drivers further to clearly define the most significant problem(s) that might need to be addressed.
- **We will explore a range of mechanisms that could reduce the bias toward capex.** We will consider various options for addressing any potential bias, including a ‘totex’ approach as one potential option, amongst others. As part of this assessment we intend to examine how totex and other potential solutions have performed in other jurisdictions.
- **The ongoing role of the DMIS.** The ongoing role of the DMIS will require consideration following assessment of a broader range of reform options. Reform of the DMIS is one potential option we intend to explore.

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?
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?
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?
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?

3.4 We propose to explore the incentive implications of DNSPs being designated ‘distribution system operators’

Growth in CER and other small-scale energy assets are making distribution systems more operationally complex. These changes are requiring new ‘distribution system operator’ (DSO) functions to be performed. Energy Ministers have agreed that DNSPs should formally be assigned responsibility for undertaking these roles. The extent to which these new functions are sufficiently incentivised by the existing framework requires further evaluation, which we intend to explore through this review.

3.4.1 New DSO roles are required to manage the distribution system

Technological development - in particular the growth in CER - is resulting in large numbers of distribution-connected assets that operate flexibly and which are engaging with the energy market or creating other system stability implications. These changes are making the distribution system operationally more complex and require new tools and systems. As a result, DNSPs are increasingly needing to take a more active real-time, operational role to coordinate these assets and maintain the distribution system within its technical operating parameters. These assets also require coordination with the broader energy system in order to optimise whole of system outcomes, given their growing scale and significance relative to other sources of generation and load. This DSO role will have an increasing importance for consumer outcomes as opportunities for CER to participate in the energy system grow.

Box 8: What is a 'DSO'?

In the Australian context, the term DSO describes a role that extends beyond a DNSP's traditional functions of building, maintaining and operating distribution network assets. Compared to a traditional DNSP, a DSO takes more active responsibility for managing and optimising CER resources connected to their nework, as well as the interactions between their network and the broader electricity system. In the Australian context, the CER Taskforce recognised that existing DNSPs already undertake many DSO functions.

A simple way to express the distinction is that a DNSP owns, builds, maintains and operates its own distribution network assets. A DSO has a role in actively managing the assets connected to its network and optimising the interaction between the distribution network and the wider power system.

In 2025 the CER Taskforce progressed work under the *Redefining roles and responsibilities for power system and market operations in a high CER future* (M3/P5 workstream) to clarify DSO roles and responsibilities. In the NEM context, the CER Taskforce divided the DSO role into four core responsibilities that describe the principal functions that DNSPs would increasingly perform as DSOs:[168]

1. **Active system management**: Actively manage network assets, CER and flexible loads to achieve safe, reliable and efficient operation of the distribution system in a two-way powerflow environment.
2. **Enabling CER flexibility**: Employ a spectrum of approaches and mechanisms to value, incentivise, procure and operationally coordinate energy, flexibility and other system services from CER.
3. **Transmission–distribution coordination**: Active coordination between the system operators and network operators to enable operational visibility and data exchange required for operations, and for system security and reliability.

168 Department of Climate Change, Energy, the Environment and Water – Consumer Energy Resources Taskforce, *Redefining roles and responsibilities for power system and market operations in a high CER future – Final advice to Ministers to progress M3/P5 priority of the National CER Roadmap*, December 2025, p. 27.

4. **Integrated distribution system planning**: Perform long-term distribution system planning, in consultation with the system operator (AEMO in the NEM) and relevant transmission network, as an integral part of advanced whole-system planning.

The CER Taskforce also identified approximately 20 specific tasks that it considered to be DSO activities. See the *Redefining roles and responsibilities for power system and market operations in a high CER future - Final advice to Ministers to progress M3/P5 priority of the National CER Roadmap* (December 2025) report for further information.

3.4.2 Energy Ministers have agreed DNSPs will be formally assigned DSO responsibilities

Energy Ministers agreed in December 2025 to formalise DNSPs as the DSO in the NEM.[169] This decision sets the forward path for assigning responsibility and accountability to DNSPs to undertake DSO activities, provide them with the necessary powers, and establish rules-based expectations, rights and obligations governing how the role is performed.

Key implementation steps proposed by the CER Taskforce to formalise DNSPs as the DSO under the regulatory framework included processes to:[170]

- Embed DSO rights and obligations in the relevant energy laws or rules. The Commonwealth Department of Climate Change, Energy, the Environment and Water is leading work across jurisdictions to formalise these rights and obligations in the NER.
- Establish specific DSO reporting requirements, led by the AER. This work is due to commence in 2026.
- Determine appropriate incentive structures to maximise DSO outcomes for consumers. **This Review will progress this work.**

Accordingly, we intend to explore through this Review whether changes are required to the incentive framework to support DSO activities in a way that maximises outcomes for consumers.

The expected work program on DSO rights and obligations work is likely to have significant implications for the work on DSO incentives. While this Review presents an important opportunity to consider DSO incentives in the context of the broader package of incentives, we acknowledge the need to work flexibly to accommodate further developments in the DSO expectations, rights and obligations as that policy work progress. We will seek to further refine the scope of the DSO incentives work under this Review as the forward pathway for the DSO rights and obligations work program progresses.

3.4.3 We will explore the need for specific DSO incentives under this Review

We will need to distinguish between obligations and incentives for DSO activities

In considering whether new incentive arrangements are required to support DSO activities, we will need to consider which DSO roles and responsibilities are most appropriately enacted through obligations and minimum standards, and which may require or warrant the use of incentive schemes to maximise consumer outcomes.

Our starting point is that new incentive schemes should be considered only in very specific circumstances, where the demonstrated case is strong, given the potential challenges and risks

169 Energy and Climate Change Ministerial Council, *Meeting Communique*, 16 December 2025.

170 Department of Climate Change, Energy, the Environment and Water – Consumer Energy Resources Taskforce, *Redefining roles and responsibilities for power system and market operations in a high CER future – Final advice to Ministers to progress M3/P5 priority of the National CER Roadmap*, December 2025, pp. xiv-xv.

associate with new schemes. We set out below some of our initial thinking on how to make this assessment. We are interested in stakeholder feedback on these points.

We consider incentive schemes may be warranted in cases where most or all of these conditions hold below:

- **Performance above the minimum standard would deliver material consumer benefits:** This includes cases where consumers are better off and would be willing to pay for increased service quality, but without an incentive DNSPs may stop at compliance.
- **Obligations cannot overcome enforcement or information problems:** This includes cases where regulators cannot readily observe effort or decision quality.
- **New approaches are needed to improve consumer outcomes:** This includes cases where DNSPs must actively pursue innovative approaches in order to unlock consumer value. These new approaches may carry risk and uncertainty for DNSPs, be subject to countervailing incentives under the framework, or face organisational or cultural barriers by virtue of being new and untested.
- **Performance can be measured and attributed:** This includes cases where desired outcomes are within a DNSP's control and can be attributed to its actions with a high degree of certainty.

However, the above conditions must be weighed against the drawbacks and risks associated with introducing new incentive schemes. These include:

- **Cost to consumers**: Financial incentive schemes are likely to come at a cost to consumers. The use of 'symmetrical' incentives (ie the use of both payments and penalties) is also relevant when considering consumer cost and value.
- **Added complexity and administrative costs**: Incentive schemes add regulatory complexity and administrative costs for DNSPs, the AER and other stakeholders. These costs may outweigh the benefits of any scheme or act as a deterrent to participation and the effectiveness of any scheme.
- **Risk of unintended consequences**: Any new or amended scheme must be considered as part of the broader package of obligations, incentive schemes and other regulatory arrangements applying to DNSPs. The impact on other parts of the framework would need to be carefully considered.
- **Verification challenges and risk of gaming**: DNSPs should only be rewarded for outcomes that are within their control and can be clearly attributed to actions taken.

Incentives may be appropriate to support specific DSO activities and outcomes

Incentives may have a role in supporting the four core DSO functions: active system management, enabling CER flexibility, transmission-distribution coordination, and integrated distribution system planning.

Minimum obligations are likely to be necessary to set enforceable expectations for most or all of these DSO functions. However, performance above minimum standards could also deliver material consumer benefits where DSO functions are performed well, including through:[171]

- reduced network congestion and the need for network augmentation
- reduced wholesale market costs and market price volatility
- offset large-scale generation requirements by generating and storing electricity locally

171 Department of Climate Change, Energy, the Environment and Water – Consumer Energy Resources Taskforce, *Redefining roles and responsibilities for power system and market operations in a high CER future – Final advice to Ministers to progress M3/P5 priority of the National CER Roadmap*, December 2025, pp. vii.

- contribution to system security services (for example battery storage providing frequency support or voltage control)
- provision of local back-up for essential loads during grid outages and assist with outage recovery.

One potential gap in the existing framework is the alignment of DNSPs' actions with whole of system outcomes. DNSPs are accountable for outcomes on their own networks and may not consider the implications of their decisions in a way that maximises whole of system outcomes. As noted in section 3.2.4, one of the reasons the DMIS was introduced was in recognition of this limitation, however the DMIS only applies to certain types of NNO opex and is unlikely to apply to many DSO activities.

The scope of 'whole of system' outcomes, how these outcomes might be measured, and whether it is appropriate for DNSPs to capture some of these broader benefits would all need to be carefully considered.

With regard to whole of system outcomes, the CER Taskforce described the DSO's role as:[172]

> *The role of distribution system operators (DSO) is critical in achieving efficient whole-of-system outcomes through balancing a combination of (sometimes competing) objectives in managing two-way power flows on the distribution system and supporting the broader power system. The role of DSOs differs from traditional network operations, which focus on the key objective of the reliable, one-way delivery of power to consumers by managing their network asset.*

Defining the 'whole of system' that DSOs need to consider would be an important policy decision in designing any such incentives. Box 9 below highlights some of the considerations for this definition.

Box 9: What are 'whole of system' benefits?

The policy development informing the DSO transition often refers to 'whole of system' benefits. Broadly, these are benefits that can be achieved when a DSO makes planning and operational decisions that maximise value beyond its own distribution network, at an efficient cost.

The CER Taskforce focused on the benefit of reducing total electricity costs to all electricity consumers. This could include, for example, reduced distribution and transmission expenditure, lower wholesale market costs, improved system security, reduced curtailment and greater value from CER.[1]

In its broader form, it can also include wider customer, social and environmental benefits, and focusing on how to improve the efficiency of the overarching system of digital and physical infrastructure, system operators, transmission and distribution networks, aggregators and consumer agents, system-connected assets (including CER) and market platforms.[2]

The National Electricity System Operator in the UK takes a narrower electricity-system framing. It emphasises whole system operations and coordinated decisions across markets, system operations and network development, particularly across the transmission-distribution interface, to deliver efficient outcomes and value for consumers.[3]

172 Department of Climate Change, Energy, the Environment and Water – Consumer Energy Resources Taskforce, *Redefining roles and responsibilities for power system and market operations in a high CER future – Final advice to Ministers to progress M3/P5 priority of the National CER Roadmap*, December 2025, p 16.

[1] Department of Climate Change, Energy, the Environment and Water – Consumer Energy Resources Taskforce *Redefining roles and responsibilities for power system and market operations in a high CER future – Final advice to Ministers to progress M3/P5 priority of the National CER Roadmap*, December 2025, pp ix, 29, 35-36, 112.

[2] Energy Catalyst, *Distribution System Operator (DSO) Models (Report 4 of 5)*, August 2025, pp 5, 55.

[3] National Grid ESO, *Enabling the DSO transition: a consultation on the ESO's approach to Distribution System Operation,* 2021, pp 5–6, 18.

There also remains a question as to whether the framework, and any potential incentives, should focus on encouraging the DSO to deliver the appropriate **quality** and **depth** of coordination:

- *Quality of coordination* concerns how effectively the DSO supports and enables CER and other parties to be coordinated in ways that maximise whole system benefits
- *Depth of coordination* concerns the extent of the DSO's responsibility and accountability. That is, whether it is merely expected to remove obstacles to parties coordinating with one another, or whether it must also establish the pathways, platforms and processes through which that coordination occurs.

3.4.4 Our initial area of focus will be on supporting whole of system outcomes

We have identified the following topics as areas for further exploration:

1. **Implications of the definition and scope of whole system benefits for incentive design:** the appropriate incentive framework will depend on which benefits DSOs are expected to consider. Different approaches could, for example, include benefits to the distribution network, transmission system, wholesale market, system security, CER owners or consumers more broadly. A wider scope may support better overall outcomes, but could also make performance harder to measure, attribute and reward. We therefore intend to consider how different choices about the definition and scope of whole system benefits would shape the DSO role and the design of any potential associated incentives.
2. **The potential need for incentives to consider broader system benefits in operational and planning decisions:** This includes cases where DSO actions provide broader system benefits, including for example, optimising the availability of network capacity so that CER can participate in the wholesale market. There may also be only a weak incentive for DNSPs to expend additional effort to identify and develop planning options that maximise benefits across transmission, wholesale markets and other parts of the system. The revenue determination process and the RIT-D processes enable consideration of broader system benefits in planning decisions, but they do not necessarily reward networks for searching for options that deliver greater whole system value, nor for making operational decisions that suppport realisation of these benefits.[173]
3. **The potential need for incentives to support the right quality and depth of coordination:** active system management depends not only on whether coordination occurs, but on how effectively it occurs and how much responsibility the DSO carries for making it happen. The quality of coordination concerns how well the DSO removes barriers, enables participation and supports CER and other distribution-connected resources to be used in ways that maximise whole system benefits. We also need to consider whether such an incentive would appropriately motivate a DSO to enact the right 'depth' of coordination. We intend to consider whether incentives are needed to encourage DSOs to improve both dimensions beyond minimum regulatory requirements, noting that a broader incentive that shares contributions to whole system benefits may be sufficient.

173 Broader system benefits are able to be considered in the revenue determination process when DNSPs propose expenditure related to CER integration; see: AER, *DER integration expenditure guidance note*, June 2022. Broader market benefits are also able to be considered under the RIT-D; see: AER, *Regulatory investment test for distribution*, November 2024,p. 6.

Question 6: 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?
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.
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?

3.5 We propose to explore the concept of 'efficient' network utilisation

3.5.1 'Efficient' network utilisation maximises consumer value from the network

Network utilisation refers to how much an electricity network is being used by its consumers, expressed relative to its maximum potential usage.[174] Generally, higher utilisation represents an improvement in consumer outcomes as it indicates more productive use of network infrastructure, up to a certain point. Consumers are best off when utilisation is at an 'efficient' level where consumer value is maximised[175] - in economic terms the point where the marginal cost of using the network capacity equals the marginal value consumers derive from it. Beyond this point, increased utilisation results in marginal costs exceeding the marginal value of additional use (eg due to congestion, asset degradation or reliability impacts).

In considering opportunities to better target network utilisation at 'efficient' levels, we propose to explore the following two questions:

- **How should we define 'efficient' network utilisation in the context of the NEM**? Existing utilisation metrics may not capture what we mean by 'efficient' utilisation for a system in transition.
- Once we have answered the first question, **what features of the existing regulatory framework incentivise NSPs to improve network utilisation? And are any additional incentives necessary?**

3.5.2 How should we define 'efficient' network utilisation in a transitioning system?

Network utilisation is currently measured by assessing maximum demand observed at each substation over a year relative to the maximum capacity of those substations.[176] It is a measure of 'headroom' for maximum demand. By this measure network utilisation has decreased since the mid-2000s, largely due to increases in zone sub-station capacity during this period, as shown in figure 3.9. Some of this investment was driven by changes to jurisdictional reliability standards and forecast demand growth in NSW and Queensland, which led to systematic investment in zone substation transformer capacity from 2009 to 2014.[177] Utilisation has remained relatively stable since 2014, once zone substation capacity stopped increasing.[178]

174 AER (2025) *Electricity and gas networks performance report*, 2025, pp 35-37.

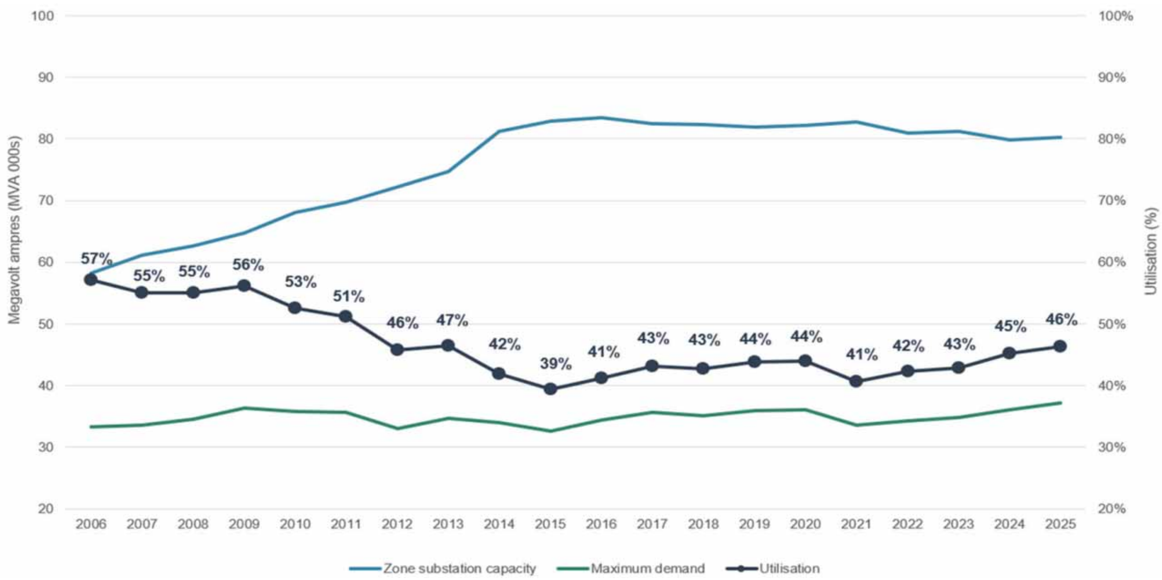
175 We note that network utilisation may vary across NSPs because of differences in network characteristics and consumer demand patterns. Key determining factors include customer density and jurisdictional reliability standards.

176 AER, Electricity and gas networks performance report, 2025, p. 36.

177 AER, Network performance report, 2026, p. 33.

178 We note that efficient utilisation rates will be below 100 per cent as NSPs: typically retain some level of redundancy to maintain their network's reliability; may proactively augment their network to efficiently meet demand growth over time; experiencing a change in consumer preferences, for example by those who are increasingly self-sufficient and only draw on their networks when needed (e.g. during prolonged cloud cover).

Figure 3.9: Network utilisation levels - DNSPs



Source: AER, *Network performance report*, 2026, p 33.

Existing utilisation metrics do not capture the full picture

Based on current metrics network utilisation appears low, however existing metrics may not be a strong indicator of network efficiency for an energy system in transition. This is because the current metrics only focus on a network's capacity during peak demand.

The focus on peak demand provides insight into how efficiently NSPs manage consumers' peak electricity demands to meet network reliability standards and prevent power outages. However, there is growing interest in understanding how efficiently networks are utilised across all periods of time, particularly for distribution networks. This reflects the challenges being created by minimum demand for system security as well as the emergence of new distribution services, such as export services for CER.[179]

In this environment the existing utilisation metrics may no longer provide sufficient insights on the efficient use of networks as they do not account for:[180]

- two-way energy flows driven by the provision of export services
- changing utilisation rates at different times of the day
- minimum demand
- utilisation of different asset types across differing levels of the network, particularly for levels of the network below the zone substation, and
- local network issues, as there may be specific sections of the network that are constrained.

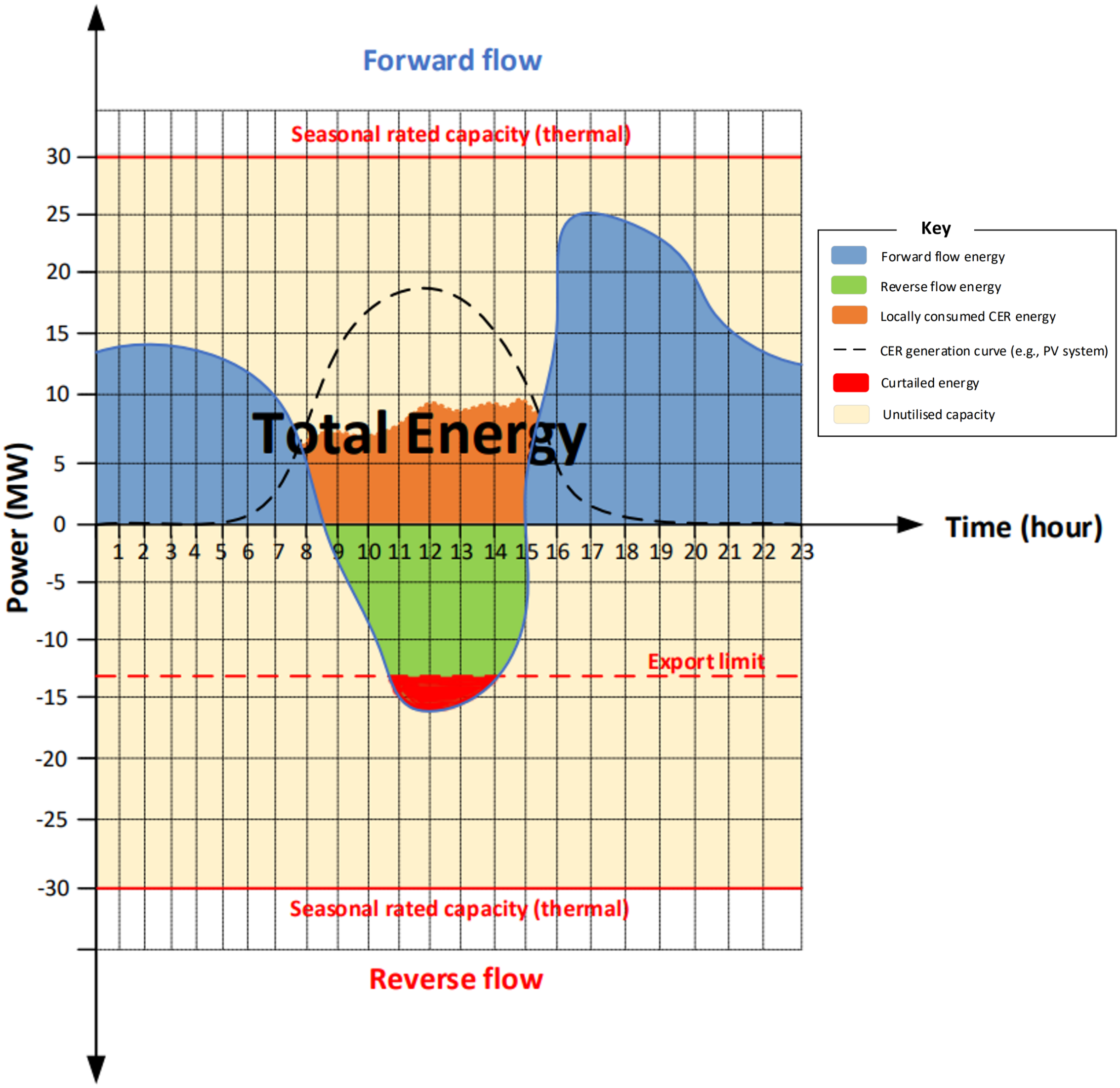
The existing utilisation metrics also do not account for capacity that has already been contracted, which is becoming increasingly important for some large connecting customers. For example, data centres may request and pay for capacity before they are connected to the network, or in advance of when they need it (e.g. if the centre is being built in phases). In this situation, utilisation may appear lower even though the additional capacity is fully funded by a customer.

179 See for example, UTS, *Reimagining Network Utilisation in the Era of Consumer Energy Resources*, December 2024.

180 UTS, *Reimagining Network Utilisation in the Era of Consumer Energy Resources*, December 2024, pp. 17-18.

Figure 3.10 below provides an illustrative example of how power flows may look on a network across a single day. It demonstrates that energy exports would not be captured by traditional utilisation metrics because energy exports create a reverse flow and so are not included in maximum demand. In addition, traditional metrics do not capture self consumption from CER or consideration of minimum demand.

Figure 3.10: Traditional metrics of utilisation do not account for volume or two way flows



Source: UTS, *Reimagining Network Utilisation in the Era of Consumer Energy Resources*, December 2024, p. 23.

We note that the prevalence of these issues will vary between networks. However, it highlights that there is a growing need to understand how efficiently networks are being used outside of peak periods, which existing utilisation metrics are unable to measure.

Work is underway that may improve utilisation measurement

The Commission published the *Enhancing Distribution Network Planning and Reporting final rule* on 16 July 2026. The final rule requires DNSPs to publish distribution network data in accordance with guidelines to be developed by the AER.[181] While the AER will consult on the appropriate data to be included in the guidelines, we expect it will draw on its previous work in the Network Visibility Project.[182] As such, we anticipate that the information available from the guidelines will support the development of new utilisation metrics, including for sections of the distribution network below the zone substation level, subject to further consultation with stakeholders.

The AER has also identified network utilisation as an area for future work. For example, in its recent consultation on network performance reporting for regulated electricity and gas networks, the AER found there was unanimous support for improving network utilisation metrics. It also found stakeholders supported introducing new network utilisation metrics. The AER noted it plans to work with stakeholders in the second half of 2026 to discuss this feedback and the potential options for future network performance reporting.[183] We intend to work closely with the AER on further work in this area.

3.5.3 How does the existing regulatory framework incentivise 'efficient' network utilisation and is a specific utilisation incentive needed?

While there are no specific utilisation incentives under the current framework, some of the existing incentive schemes are likely to support efficient network utilisation, at least to an extent. The CESS, DMIS and STPIS may incentivise NSPs to deliver utilisation (as currently measured) at an efficient level in the following ways:

- The CESS (in combination with the broader ex ante framework) encourages NSPs to avoid or reduce the scale of network investment. This typically keeps network capacity relatively lower, at least in the near term when expenditure is deferred. It also leads to improved utilisation under standard utilisation metrics, which measure peak demand against total network capacity.
- The STPIS discourages networks from reducing or deferring capital expenditure at the expense of service quality. This helps to ensure that higher network utilisation is not driven by deferring network augmentations when they are needed to support service delivery.
- The DMIS supports higher utilisation by providing stronger incentives for DNSPs to select NNOs. This can further support a DNSP to defer planned network augmentation (e.g. through better demand management) and improve utilisation.

Similarly, performance reporting by the AER also provides NSPs with a reputational incentive to improve their network utilisation whilst retaining service quality. The AER conducts annual performance reports, including reporting on network utilisation and certain service quality measures (e.g. reliability). An NSP may then decide to improve, or maintain, its network utilisation to avoid being perceived as less productive or efficient than by other networks.

We considered alternative utilisation incentives as part of our Pricing Review

The Commission considered different approaches for incentivising NSPs to improve network utilisation as part of our recent *The Pricing Review: Electricity pricing for a consumer driven future* (Pricing Review). We identified in the draft report that a network utilisation incentive could reward NSPs where:[184]

181 Clause 5.13A.1(a) of the Enhancing Distribution NetworkPlanning and Reporting final rule.

182 AEMC, *Enhancing Distribution NetworkPlanning and Reporting, Final determination*, 16 July 2026, p. 27.

183 AER, *Network performance reporting for regulated electricity and gas networks - final report*, December 2025, p. 13.

184 AEMC, *The pricing review - Electricity pricing for a consumer-driven future, Draft report*, 11 December 2025, pp. 108-109.

1. they improved against a utilisation metric designed so that improvements against the metric reflect the network better meeting consumer needs, or
2. they reduce inefficient constraints on demand (see Box 10 for an example of this).

> **Box 10: A utilisation incentive could be designed to reduce inefficient network constraints**
>
> Network tariffs and static or dynamic operating envelopes can constrain imports or exports below the level that would otherwise be efficient. Such charges or limits may be appropriate when capacity is scarce, but can unnecessarily suppress network use when spare capacity is available. For example, charging a battery owner a per kWh charge to export energy when there is no congestion on the network will likely reduce their level of export, reducing the use of that network below efficient levels.
>
> A utilisation incentive could reward NSPs for reducing avoidable price-based or technical constraints, increasing network use during unconstrained periods. Networks would retain incentives to use tariffs and proportionate limits to reduce peak demand when the network is congested. Such uses could improve utilisation over time by helping to defer, avoid or reduce the scale of network augmentation.

Some stakeholders expressed concern about utilisation-based incentives in their submissions to the draft report.[185] They noted that many factors outside an NSP's control would affect the potential penalties and rewards under the incentive. Other stakeholders further noted the difficulties in creating an effective utilisation incentive scheme that achieves the desired outcome.[186]

Pricing reform is a complementary way to improve some aspects of network utilisation

The Pricing Review recommended reforms to move network tariffs towards its long-term vision for more efficient and equitable pricing.[187] Under that vision, shared network costs would be recovered in ways that better distribute contributions to those costs between consumers. The recovery of these costs would be designed to:

- minimise distortions to consumer behaviour, such as tariffs that encourage consumers to consume less energy when there is no congestion on the network
- potentially differentiate between consumers according to the benefits they receive from the shared network, including by reference to their connection characteristics or historical consumption or demand.

The second part of that long-term vision was for increasingly dynamic price signals that would target congestion when and where it occurs. The dynamic component could be zero when the relevant part of the network was unconstrained. The signal would then operate symmetrically during congestion, charging for actions that worsen a constraint and rewarding actions that relieve it. For example, they would discourage imports and reward exports during demand-driven congestion, while discouraging exports and rewarding imports during export-driven congestion.

If implemented successfully, these reforms could support improved consumption-based network utilisation. Moving shared network costs away from volumetric charges would reduce consumers being unnecessarily discouraged from using energy when spare capacity is available.[188] Dynamic

185 ENA, *submission to the draft report*, 20 February 2026, p. 3.
186 See, eg, submissions to draft report: Ausgrid, p. 11; ENA, p. 3; Endeavour Energy, p. 5; Evoenergy, p. 5,
187 AEMC, *The pricing review: final report*, June 2026.
188 For further discussion see AEMC, *The pricing review, Discussion paper*, June 2025, pp. 57, 75.

signals would simultaneously shift imports and exports away from the times and places where they worsen constraints and encourage them where they relieve constraints.

The combined effect would be greater use of spare capacity and less pressure at constrained peaks. All else equal, this would increase the amount of energy transported relative to the network capacity required, improving utilisation over time and reducing or deferring augmentation. In the Pricing Review's long-term vision, dynamic network pricing would become the primary mechanism for managing congestion, complemented by flexibility markets and other non-tariff tools. These other tools would also work to improve the utilisation of the network.

We further note that ECA has indicated it will likely submit a rule change request to make network tariffs work for Australia's modern, two-way electricity grid.[189]

We will consider potential interactions with the recommendations of our Pricing Review, and any potential rule change requests, as we progress this review.

3.5.4 We propose to explore the incentives that the framework provides for efficient utilisation

We propose to explore:

- **Previous and ongoing work on network utilisation metrics for the NEM given the changes underway in the sector**. This will include consideration of which metrics are most likely to accurately align with consumer value going forward.
- **Whether any additional regulatory incentives or mechanisms might be needed to encourage greater network utilisation**. This will include considering whether new mechanisms could improve utilisation beyond the current framework. We will also consider their potential costs and risks, including complexity, duplication and rewarding networks for outcomes beyond their control.
- **Interactions between pricing reform and utilisation incentives**. In particular, we will consider whether any transitional or regulatory mechanisms would be useful to encourage the better network utilisation in the period during which any potential pricing reforms are implemented and take effect.

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?
2. How could such a mechanism be designed and how could measurement limitations be addressed?
3. Are there other options to drive efficient utilisation that you would like the AEMC to consider?

189 Energy Consumers Australia, *Media Release – Energy Consumers Australia welcomes critical reforms to network tariffs in the AEMC's Pricing Review*, 18 June 2026.

3.6 We propose to explore incentives for NSPs to innovate over time

3.6.1 How could incentives encourage innovation by NSPs during the energy transition?

Innovation is necessary to improve consumer outcomes over the long-term

Investment by NSPs in research and development (R&D) and their adoption of new and innovative approaches are essential to improving consumer outcomes over the long-term - *dynamic efficiency* in economic terms.[190] Innovation is necessary to improve productivity over the long-term, and productivity improvements result in better outcomes for consumers and flow onto improved competitiveness, efficiency and growth across other sectors of the economy.[191]

The energy transition is creating new opportunities for networks to innovate and drive dynamic efficiencies in the way in which they provide network and system operation services. Trends underway including digitalisation and continued cost improvements in energy storage are enabling the system to be managed in more dynamic and cost effective ways. At the distribution level CER aggregators, virtual power plant (VPP) operators and home automation services are increasingly playing a role in driving more efficient electricity system operation. At the transmission level this includes new opportunities to meet network needs with NNOs. More granular, real-time data will support better operational and planning decisions. [192]

Regulated monopolies like NSPs are likely to under-invest in innovation

NSPs are likely to under-invest in innovation (without additional incentives) relative to an optimal level because:

- NSPs are unlikely to capture all the upside rewards resulting from successful innovation. To the extent that innovation results in future cost reductions, NSPs will pass the majority of these gains onto consumers in future regulatory periods. Further, as monopoly businesses, NSPs do not benefit from any material competitive advantage against rivals as a result of innovation.[193]
- NSPs may still face down-side risk. If R&D does not yield results or costs occur significantly before the benefits, NSPs may be financially penalised under the regulatory framework.[194]
- The uncertain nature of some innovation spending may not meet relevant expenditure criteria and therefore may not be approved through the revenue determination process.[195]
- NSP investors may have a preference for low risk and stable returns, which are typically associated with regulated utility investment. Such investors may preference cost minimisation over innovative approaches that carry higher upside but higher risk and uncertainty.[196]

190 KPMG, *Optimising network incentives, Alternative approaches to promoting efficient network investment - A report for the Energy Market Transformation Project Team*, January 2018, p. 6.

191 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2025.

192 See discussion of changes occurring within the energy system in AER, *Future of electricity network regulation*, Information paper, p 46-51.

193 AER, *Explanatory statement, Draft demand management innovation allowance mechanism, Electricity distribution network service providers*, August 2017, p. 10.

194 AER, *Explanatory statement, Draft demand management innovation allowance mechanism, Electricity distribution network service providers*, August 2017, p. 10.

195 KPMG, *Optimising network incentives, Alternative approaches to promoting efficient network investment - A report for the Energy Market Transformation Project Team*, January 2018, p. 10.

196 KPMG, *Optimising network incentives, Alternative approaches to promoting efficient network investment - A report for the Energy Market Transformation Project Team*, January 2018, p. 10.

Current arrangements may not adequately compensate for barriers to innovation

Measures have been taken to address the barriers noted above including introduction of the DMIAM and introduction of regulatory sandboxing. However, these schemes may have limited effectiveness, and structural barriers created by the framework may still persist.

- The DMIAM was introduced to provide DNSPs and TNSPs with an innovation allowance to support R&D. However, the existing DMIAM provides relatively low levels of funding, with annual expenditure capped at $200,000 plus 0.075 per cent for DNSPs or plus 0.1 per cent for TNSPs.[197] In practice this is typically sufficient to fund a handful of small trial projects by NSPs. In total DNSPs were granted an average of $8.3 million per year under the mechanism over the five years from FY2021-2025.[198]
- A regulatory sandboxing framework was introduced to enable NSPs and other parties to trial new policy initiatives via trial rules and trial rule waivers. However, the sandboxing arrangments are not specifically focussed on incentivising or funding the trial of new technologies and commercial initiatives related to technological deployment.
- Absent an innovation allowance, the EBSS and CESS may deter innovative research and development initiatives that may arise within period. This is because an NSP risks being penalised (or subject to fewer rewards) under the EBSS for research and development initiatives that provide no guarantee that they will deliver efficiencies within the same period.

Against the background of these potential limitations, we are interested in stakeholder views in how the incentive framework can drive greater levels of innovation from NSPs to deliver dynamic efficiency benefits for consumers.

Question 8: Are changes required to better incentivise network innovation?

1. What are your views on the effectiveness of the incentive framework for network innovation?
2. What improvements can be made to this framework to drive greater levels of innovation?

197 The $200,000 is indexed for inflation and is based on $ real (2017) for DNSPs and $ real (2021) for TNSPs, reflecting different implementation dates of the scheme for DNSPs and TNSPs.

198 Source: AEMC, based on data provided by the AER.

4 Risk allocation and compensation

The regulatory framework allocates risks between NSPs and consumers and gives NSPs a reasonable opportunity to recover efficient costs, including a return commensurate with the risks they bear. Together, these arrangements form the risk-reward package that underpins efficient investment, access to capital and the delivery of network services in consumers' long term interests.

As the energy system transforms, the nature and scale of risks facing NSPs and consumers is changing. This chapter sets out:

- why the framework allocates and compensates for risk, and the overall objectives of the risk-reward package (section 4.1)
- how the current framework allocates and compensates for risk, including the role of expenditure allowances, forms of control, the rate of return and intra period adjustment mechanisms (section 4.2)
- the potential issues with the risk-reward package that we propose for further investigation, including:
  - whether the framework continues to appropriately allocate risk between NSPs and consumers as uncertainty increases (section 4.3 and section 4.4)
  - how the framework should support efficient anticipatory investment (section 4.5)
  - potential diverging NSPs risk profiles and the AER's flexibility when developing the rate of return instrument (RoRI) under the NEL (section 4.6).

4.1 Why does the framework need to allocate and compensate for risk?

Electricity networks deliver essential services through capital-intensive, long-lived assets, the costs of which are largely sunk once investment decisions are made. Because network capacity cannot be easily withdrawn or redeployed if demand, cost, technology, regulatory or environmental factors change, investments occur under some degree of uncertainty. That uncertainty is heightened by the way the framework operates. Revenue determinations are set ex-ante, typically for five-year regulatory periods, based on forecasts of future demand, costs and operating conditions. The future rarely unfolds exactly as forecast, so actual outcomes often diverge from what was assumed when a determination was made.

Given this context, regulation must provide NSPs confidence that they will recover efficient costs, whilst also imposing discipline on NSPs to invest efficiently. Sunk and largely irreversible investment creates regulatory risk given that once an NSP commits capital, it cannot easily withdraw or redeploy that investment if future regulatory decisions were to affect cost recovery. If investors do not have confidence that the framework provides a reasonable opportunity to recover at least their efficient costs, they may delay efficient investment or require a higher return to compensate for that risk.

These arrangements give effect to the risk-reward package for NSPs, which includes consideration of:

- **Risk allocation**: The framework should allocate risks to the party best placed to manage, influence or absorb them. If NSPs bear risks they cannot efficiently manage, network investment may be discouraged, and consumers may face lower reliability and/or higher financing costs incurred by NSPs. If consumers bear risks NSPs are better placed to manage, they may pay more than necessary.

- **Compensation**: NSPs accept revenue and price regulation in exchange for a reasonable opportunity to recover at least their efficient and prudently incurred costs, including a return commensurate with the risks they bear. [199] For consumers, these arrangements support efficient investment and reduce long term network costs.

The Review will consider whether the risk-reward package continues to strike an appropriate balance as the energy system changes and NSPs face different risks in the transition to a net zero system. As set out above, it is important that the framework appropriately and through the suitable regulatory tools:

- allocates new types of risks between NSPs and consumers (see below for further detail)
- compensates NSP for any new risks to ensure investments in the long term interest of consumers.

4.1.1 The framework allocates different types of risks

The regulatory framework allocates risks between NSPs and consumers. These risks can be grouped into four broad categories:

- **Demand risk:** The risk that actual electricity demand for network services is higher or lower than forecast. Electricity demand has a strong bearing on the overall cost of the electricity network.
- **Cost and delivery risk:** The risk that the cost of providing various network services is higher or lower than forecast. This includes prices of project development inputs for NSPs (e.g. fuel and construction materials) which are determined in global commodity markets or the cost of skilled labour which can be subject to shortages that are difficult to predict over a regulatory period. It also includes delivery timing risk, whether an NSP begins recovering costs for a new asset once expenditure is incurred, or only once the asset is commissioned. The timing of cost recovery determines whether consumers or NSPs bear the risk of project delays.
- **Asset stranding risk:** The risk that network assets become under-utilised, are expected to remain under-utilised, or are no longer required to provide services. Stranding risk is relevant for industries where rapid technological change can render existing assets obsolete quickly or in which future demand is uncertain.
- **Regulatory and sovereign risk:** The risk arising from the scope of a regulator's discretion, or from potential impacts of government policy or decisions. Examples of this type of risk include the introduction of new policies or legislation that result in changed circumstances for NSPs (e.g. compared to the circumstances under which investments were made), or generally alter businesses' costs.

4.1.2 The framework differentiates between systematic and businesses/project specific risk

The risks discussed above can be grouped into two types of risk, systematic and business/project specific risk:

- **Systematic** describes demand, cost, stranding or regulatory risk that is market-wide and cannot be diversified away. Investors require compensation for bearing this risk. Given the systematic nature of these types of risks, compensation for systematic risk occurs through the allowed rate of return.
- **Business/project specific** risk is the portion tied to an individual firm or project. NSPs' can manage or diversify against this risk, so it is addressed through the targeted mechanisms

199 As underpinned by the revenue and pricing principles in the NEL, see section 7A(2) of the NEL.

designed to allocate risk and support an NSPs operation where appropriate rather than through the rate of return.

In the context of the energy transition and the changing nature of risks that NSPs face today and into the future, the Review will assess whether the risk-reward package continues to operate in the interest of consumers. Specifically, the Commission intends to consider further whether:

1. risks are placed with the party best able to manage them or most appropriately bear their consequences
2. risks are allocated across the package as a whole in a cohesive way, and
3. a different allocation would better promote the NEO.

4.2 How does the existing framework allocate and compensate for risk?

The current regulatory framework allocates and shares risk between networks and consumers using the regulatory tools set out below, based on the different types of risk. These regulatory tools seek to place risk with the party best placed to manage it, compensating investors for systematic risk, preserving incentives for efficient expenditure, and protecting consumers from paying for inefficient expenditure.

Fixed ex ante expenditure allowances allocate controllable cost risk to NSPs

An NSPs allowance is set in advance of each regulatory control period, based on the AER's assessment of prudent and efficient costs.[200] This places risks related to project costs and delivery, procurement and day-to-day operational efficiency with NSPs. An NSP that spends more than its allowance bears a portion of the over-spend, and one that spends less retains a portion of the saving.[201] Fixed expenditure allowances, set ahead of time (ex ante), is what preserves the incentive for NSPs to pursue expenditure efficiency, since any gap between forecast and actual cost is not automatically passed through to consumers.

Benchmarking disciplines the level of expenditure allowances

The AER uses benchmarking to assess whether an NSP's proposed expenditure is consistent with efficient costs across the sector, providing an independent check on each NSP's forecasts that does not rely solely on the NSP's own cost information. The AER publishes annual benchmarking reports for electricity distribution and transmission networks, comparing NSPs' efficiency against each other and against an efficient frontier.[202] Where an NSP's proposed expenditure materially exceeds the efficient benchmark, the AER may adjust the allowance accordingly. This process serves a complementary function to fixed ex ante allowances by disciplining the level at which those allowances are set at each reset. Together they create a two-stage incentive for ongoing opex efficiency as NSPs face pressure to outperform their allowance within the period, and an external point of reference against which any proposed increase in expenditure must be justified.

200 AER, *Expenditure Forecast Assessment Guideline* (2013, updated 2022/2024) outlines how the methodology underlying how ex-ante allowances are set.

201 This is subject to the EBSS and CESS outlined in Chapter 3.

202 AER, Annual benchmarking reports, 2025: Electricity distribution network service providers (published annually); AER, *Annual benchmarking report: Electricity transmission network service providers* (published annually). The AER uses both economic benchmarking (total expenditure efficiency) and partial indicator analysis to assess relative efficiency and inform expenditure allowance assessments at each reset.

The form of control allocates demand risk to consumers through a revenue cap or NSPs through a price cap

The form of control is a fundamental regulatory choice that determines how demand risk is shared between NSPs and consumers.[203]

Demand risk is allocated in opposite directions under each of the following forms of control:

1. **Revenue cap:** Under a revenue cap the regulator approves the total revenue allowance an NSP can recover over the regulatory period, with prices adjusted each year so that revenue collected from consumers matches the allowance. If revenue is under- or over-recovered in any year, tariffs in the following year are adjusted to make up the difference. Because revenue is fixed and prices are not, an NSP's revenue does not change with demand. Under a revenue cap consumers bear demand forecast risk, provided the NSP's costs do not change with demand.[204]
2. **Price cap:** Under a price cap the regulator sets the per-unit price of electricity based on a forecast revenue requirement. Because prices are fixed and revenue is not, a decrease in demand means a decrease in revenue for the NSP, and an increase in demand means an increase in revenue for the NSP. Under a price cap the NSP bears demand forecast risk, provided the NSP's costs do not change with demand.

For DNSPs, the AER retains discretion to apply either a revenue cap or a price cap, and in recent determinations has consistently chosen to apply a revenue cap.[205] The NER prescribes a revenue cap as the form of control for all TNSPs.

The RoRI compensates for systematic risk

Investors who commit capital to network infrastructure are exposed to systematic risk which is the risk correlated with movements in the broader economy that cannot be diversified away. The AER compensates for this risk through the allowed rate of return, set via the Rate of Return Instrument (RoRI) and calculated using a weighted average cost of capital (WACC) benchmarked to a hypothetical efficient firm.[206] The RoRI compensates NSPs for systematic, non-diversifiable risk only, not for business/project specific risk an NSP might face. Business/project specific risks are deliberately addressed by the other mechanisms in this section.

Intra period adjustment mechanisms adjust for business/project specific risk

Some risks are difficult to forecast or priced into a five-year allowance. These may include major demand changes, changes in government policy and extreme weather events. The NER provides several mechanisms that allow expenditure allowances to be adjusted after a determination has been made, i.e. intra period. While these mechanisms perform different functions, they share a common objective of managing material events that are uncertain at the time of a regulatory reset.

203 Clause 6.2.5 of the NER and the AEMC *Network regulation explainer*: Sets out the AER's discretion between a revenue cap and a weighted average price cap, and the trade-offs between them.

204 If an NSP's costs do vary with demand, then demand risk is shared, with NSPs bearing the risk of higher-than-forecast demand and consumers bearing the risk of lower-than-forecast demand.

205 Clause 6.2.5 of the NER. The AER's *2014–19 NSW and ACT electricity DNSP control mechanism discussion paper*, April 2012, provides an assessment of revenue cap vs price cap trade-offs against criteria in cl. 6.2.5(c) of the NER, including how each form affects volume risk, price stability and demand-management incentives.

206 AER, *Rate of Return Instrument – Explanatory Statement*, 24 February 2023, outlines the AER's current reasoning on WACC construction, Market Risk Premium (MRP), equity beta and gearing.

- **Cost pass through**:[207] Cost pass-through provisions allow revenue adjustments for specified events that occur during a regulatory period and satisfy defined eligibility and materiality thresholds.[208] These mechanisms seek to address external events that fall outside the normal risks expected to be managed through fixed allowances such as environmental risks from extreme weather events or political risks arising from legislative change.
- **Contingent projects**:[209] Contingent project applications (CPA's) allow an NSP to seek approval for additional revenue during a regulatory period where a project identified in its determination is triggered and the project's efficient costs can be assessed.[210] These applications link cost recovery to defined trigger events, materiality thresholds and AER scrutiny, rather than including uncertain project costs in the initial ex ante allowance. This mechanism protects both consumers and NSPs. Consumers do not fund allowances for planned projects that ultimately prove unnecessary, while networks are protected from having to deliver uncertain projects without an appropriate expenditure allowance.
- **Capex reopeners**:[211] Capex reopeners allow part of a regulatory determination to be revisited where defined circumstances arise after a determination has been made. They provide a mechanism for addressing material changes in circumstances that were not appropriately reflected in the original determination. For example, a distribution network can apply to reopen its revenue determination where an unforeseen event beyond its control, such as greater-than-anticipated demand growth, threatens system reliability and security, provided the required capex exceeds 5 per cent of the NSP's RAB and cannot be offset by reducing capex elsewhere. This 5 per cent threshold illustrates a broader asymmetry in how these mechanisms currently protect networks rather than consumers.[212]

Each intra period adjustment mechanism addresses a different type of uncertainty and operates under different thresholds, tests and consultation requirements.

Incentive schemes share performance risk between consumers and NSPs

Underspend and overspends relative to an NSP's allowance are split between the NSP and consumers under incentive schemes covering both capital and operating expenditure. An NSP that underspends its allowance keeps a share of the saving, one that exceeds its allowance bears a share of the loss. The mechanics differ slightly between capex and opex. The Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS) formalise this sharing, each generally targeting a 70:30 split between consumers and the NSP (See chapter 3.2).[213] This sharing arrangement is what allows the ex-ante framework to keep replicating the efficiency pressure of competitive markets over time. Non-financial performance risks are also shared through schemes such as the STPIS, which can reward or penalise NSPs for service quality and flow the consequences of poor performance back to consumers through lower future charges or direct payments.

207 Clause 6A.7.2, 6A.7.3, 6.5.10 and 6.6.1. of the NER.

208 A cost pass-through allows positive or negative changes in costs to be passed through to network users where those costs are associated with an external event prescribed in the NER (e.g. changes in regulatory obligations, service standards, taxes, and network support payments for TNSPs) or another event specified in the NSP's revenue determination (e.g. natural disasters), and where the costs exceed the specified materiality threshold of 1 per cent of the NSP's allowed revenue in that year.

209 Clause 6A.8 and 6.6A of the NER.

210 Contingent projects allow an NSP to apply to the AER for a limited reopening of its revenue determination to recover costs where a project identified as a contingent project (or, for TNSPs, an actionable ISP project) has had its trigger event occur, typically the successful completion of a Regulatory Investment Test (RIT-T or RIT-D) confirming the net benefit of a project proceeding, or a specified demand, generation or connection threshold being reached, and where the required capex exceeds the greater of $30 million or 5 per cent of the NSP's allowed revenue in the first regulatory year.

211 Clause 6A.7.1 and 6.6.5. of the NER.

212 See NER 6.6.5 (4).

213 As noted in Chapter 3, the exact sharing ratio under the EBSS depends on the NSPs internal discount rate and the length of time that the opex cost/saving continues for.

Ex post review protects consumers from imprudent and/or inefficient capital expenditure

The NER provides the AER with powers to review capital expenditure after it has been incurred and to exclude from the RAB any expenditure that does not meet the prudency and efficiency test.[214] This is one of the framework's most fundamental consumer protections. Because ex ante allowances are set on the basis of forecast costs, the ex post review provides a backstop that prevents consumers from funding capital expenditure that was either inefficiently delivered or imprudently decided upon, regardless of whether that expenditure was within or above the original allowance.

The ex post prudency and efficiency test asks two questions:

- **Prudency:** Was the decision to incur the expenditure reasonable, based on what the NSP knew, or should have known at the time the decision was made?
- **Efficiency:** Was the expenditure delivered at efficient cost

Where the AER determines that expenditure fails either test, it may exclude that expenditure from the RAB, meaning consumers do not fund it through future regulated revenues. This power applies to all capital expenditure.

A seperate but related process governs how ex post review interacts with the Capital Expenditure Sharing Scheme (CESS). The AER's Capital Expenditure Incentive Guidelines set out an ex post review process that can result in capital expenditure being excluded from an NSP's regulatory asset base (RAB).[215] This review is triggered under one of three limbs:

1. where actual expenditure exceeds the approved allowance (an overspend),
2. where expenditure involves related party margins, or
3. where there is a change in an NSP's capitalisation policy.

Prudency and efficiency assessments apply only to the overspend limb and the AER retains discretion over whether to apply CESS penalties following an ex post prudency assessment. For example, where the AER removes expenditure from the RAB entirely, it may suspend the CESS penalty for that portion to avoid penalising the NSP more than 100 per cent of the relevant cost.

Together, these two layers of ex post review serve complementary functions. The NER prudency and efficiency framework protects consumers from paying for poor investment decisions. The CESS ex post review preserves the incentive properties of the sharing scheme by ensuring that penalties and rewards reflect actual performance against the allowance rather than factors outside the NSP's control.

4.3 The scale and speed of the transition is uncertain, increasing demand forecast, cost and delivery risk

The sources and scale of risk and uncertainty facing the framework are dynamic and in some cases are likely increasing as the drivers of network investment change. In particular, demand forecast risk may be increasing, and cost and delivery risks are changing, each in ways that test whether the current risk-reward package continues to strike the right balance. Consumers ultimately bear the consequences of forecast error, delivery delays and inefficient expenditure.

214 Clause 6.12.1 and 6A.14.1 of the NER, ex post reviews of capital expenditure for distribution and transmission respectively. The AER may conduct a review at any time, or is required to do so in certain circumstances, including where actual capital expenditure materially exceeds the approved allowance.

215 AER, *Capital expenditure incentive guideline*, August 2025, pp. 17-25.

Over-forecasting can result in consumers funding investment that is not yet needed, while under-forecasting can delay efficient investment, increase future costs and reduce reliability outcomes.

4.3.1 Demand and forecasting risk are changing

We have identified a number of issues increasing uncertainty across several dimensions relevant to network investment in chapter 1. Demand growth is increasingly material, locational and dependent on external drivers. This uncertainty flows through to consumers, who bear the risk and cost of over-forecasting, and the reliability and price consequences of under-forecasting. Three drivers illustrate this:

- **Large discrete loads.** Data centres and other large connections can create step changes in demand that require location-specific augmentation, rather than the incremental network reinforcement NSPs have historically planned for.[216] Recent revenue determinations highlight these challenges. Demand uncertainty associated with data centres was a significant focus of the AER's assessment of augmentation expenditure for the 2026 Victorian distribution determinations. AusNet's 2026-31 proposal included $909.0 million in augmentation expenditure, a 34.5 per cent increase on the current regulatory period, driven substantially by demand growth including data centre connections.[217] Jemena similarly reported that expenditure on major customer connections, including data centres, had begun increasing significantly during the current period and was forecast to rise further.[218] The AER adjusted some augmentation forecasts and revised a number of proposals associated with uncertain demand growth, reflecting its role in testing whether consumers should bear the cost of this uncertainty upfront.
- **Electrification of the broader economy.** The pace of electrification across transport, heating and industry, including the switch from gas to electric appliances and processes, is a key assumption underlying demand forecasts. Even modest changes in the assumed rate of electrification uptake can have a material effect on projected network demand. Electric vehicle (EV) uptake is a clear example. The pace at which consumers adopt EVs is difficult to forecast several years in advance, and variation in that assumption feeds directly into projected network demand.[219]Electrification of domestic gas demand featured directly in the AER's assessment of augmentation expenditure for the 2026 Victorian distribution determinations, where demand uncertainty linked to customers switching from gas to electric appliances formed a significant part of the AER's consideration of proposed augmentation spend.[220]
- **Jurisdictional policy.** State and territory policies to support renewable energy and electrification can materially affect both the level and timing of network investment within a single five-year regulatory period. The ACT Government's 2024 Integrated Energy Plan set out a pathway to full electrification and net zero by 2045, including banning new gas connections in most land use zones. Likewise, Victoria's Gas Substitution Roadmap phased out new gas connections for new dwellings from January 2024, expanding to require all new homes and commercial buildings to be all-electric from January 2027. Change in government policy is

216 AEMO's Quarterly Energy Dynamics recorded 11 large-scale data centre projects representing 5.4 GW of maximum demand in the transmission pipeline at March 2026, a scale and concentration of load that is materially harder to forecast and site than dispersed residential and commercial growth, pp. 42-43.

217 AusNet Services, *Regulatory Proposal 2026-31*, 31 January 2025

218 Jemena, *Regulatory Proposal 2026-31*, 31 January 2025.

219 AEMO, *2024 Forecasting Assumptions Update*, August 2024, projects underlying NEM consumption approaching 200 TWh by 2030, with EVs alone expected to contribute a meaningful share of this under its step change scenario, illustrating the sensitivity of aggregate demand forecasts to electrification assumptions.

220 AusNet Services, *Regulatory Proposal 2026-31*, 31 January 2025; Jemena, *Regulatory Proposal 2026-31*, 31 January 2025.

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.

As uncertainty increases, forecast error may have more significant consequences for both NSPs and consumers. Over-forecasting, or expenditure allowances that are in excess of outturn need, may result in consumers funding investment before it is needed or paying for assets that are not fully utilised. Under-forecasting may delay efficient investment, increase delivery pressures, undermine appropriate network returns, create reliability risks or require greater reliance on intra period mechanisms that adjust revenue allowances during a regulatory period. The framework must therefore balance the risks associated with over-forecasting against the risks of under-forecasting.

4.3.2 Cost and delivery risk are changing

Beyond demand uncertainty, the energy transition is also increasing cost and delivery risk. NSPs are being required to deliver larger and more complex investment programs while coordinating with a growing range of participants across the energy system.

NSPs are facing increasing exposure to supply chain disruptions, logistics constraints, labour shortages, contractor availability risks and delays in procuring specialised equipment. Recent work on energy-sector technology supply chains identifies rising global demand, concentrated suppliers and longer lead times for key equipment as risks to project delivery. For example, high-voltage transformer lead times increased from around 50 weeks to 120 weeks in 2024, while lead times for large transformers ranged from 80 to 210 weeks.[221] Infrastructure Australia has also identified broader workforce shortages across the public infrastructure pipeline, with demand expected to exceed existing capacity in a range of occupations, posing a substantial delivery risk to major projects.[222] These pressures may be increasing the risk that actual network delivery costs differ materially from forecasts set at the start of a regulatory period.

Box 11: Case study - HumeLink

HumeLink, a 385 km high-voltage transmission line connecting Wagga Wagga, Bannaby and Maragle in southern NSW, illustrates how project cost estimates can move materially as a project progresses through each stage of assessment, delivery contracting and construction.

Table 4.1: HumeLink cost changes

Stage	Date	Cost	Change vs original estimate
Project Assessment Draft Report (PADR)	February 2020	$1.3 billion (real)	Baseline
Project Assessment Conclusion Report (PACR) and PACR addendum	July 2021, Addendum in December 2021	$3.3 billion (real)	+154 per cent
Final investment Decision	December 2024	$4.9 billion (nominal)	+ 276 per cent

221 Australian Government Department of Home Affairs, *Energy Sector Supply Chains factsheet,* November 2025.

222 Infrastructure Australia, *2025 Market Capacity Report*, November 2025, pp 42-56.

Note: numbers are approximated.

Over approximately five years, from the first RIT-T cost estimate to Final Investment Decision, HumeLink's total estimated cost rose from $1.3 billion to $4.9 billion, an increase of around 276 per cent. The escalation was driven by a combination of factors, including route and easement changes in response to landholder and community feedback, biodiversity offset costs not fully scoped in the original assessment, and broader supply chain and labour cost pressures, including extended transformer lead times and workforce shortages across the infrastructure pipeline. The largest single driver of the initial cost increase, from PADR to PACR, was biodiversity offset costs, which accounted for almost one third of the $2 billion increase. In its determination on Transgrid's HumeLink CPA, the AER determined that biodiversity offset costs should be excluded from the application of the CESS because these costs are uncertain and beyond Transgrid's control. [1]

HumeLink demonstrates that delivery risks for large greenfield transmission projects may be material.

[1] AER, *Determination - Transgrid HumeLink Stage 2 Contingent Project*, August 2024, p. ix.

Climate change and extreme weather events are likely to contribute further to increasing project cost and delivery risk. Networks may face higher resilience, replacement and maintenance costs as extreme weather and environmental conditions change. In their 2024-29 electricity distribution expenditure proposal, NSW DNSPs proposed a total of $351.6 million to address resilience related expenditure including bushfire risk, flood risk and windstorm risk.[223]

These factors affect the cost and timing of network investment and increase the likelihood that actual costs differ materially from forecast costs, particularly those build on historical analysis. If NSPs bear risks they cannot efficiently manage, they may delay efficient investment, adopt overly conservative investment strategies, leaving consumers facing higher financing costs, delayed connections or reduced reliability. Conversely, if consumers bear risks that NSPs can reasonably manage through efficient planning, contracting or project delivery, consumers may pay more without receiving corresponding efficiency benefits.

Some stakeholders raised concerns in our recent Pricing Review about how the framework allocates stranding risk as more consumers reduce their reliance on the network to procure electricity. The Pricing Review recommended moving network cost recovery away from a primarily consumption-based model, on the basis that consumers who reduce their grid imports through CER still rely on the network for reliability and to export power.[224] This Review will examine the broader question of what costs networks should recover.

Cost and delivery risks also interact closely with anticipatory investment decisions. Early procurement, advanced works, project staging and larger initial investments may reduce future cost escalation and delivery risk. However, these approaches may also expose consumers to utilisation, timing and stranding risks if expected demand or policy outcomes do not materialise. These issues are discussed further in section 4.4.

223 AER, *Final decision - Ausgrid Electricity distribution determination 2024 to 2029 (1 July 2024 to 30 June 2029)*, April 2024, Attachment 5 – Capital expenditure, p. 18; AER, Final decision - *Endeavour energy Electricity distribution determination 2024 to 2029 (1 July 2024 to 30 June 2029)*, April 2024, Overview, p. 16; AER, *Final decision - Essential energy Electricity distribution determination 2024 to 2029 (1 July 2024 to 30 June 2029)*, April 2024, Overview, p. 18.

224 AEMC, *The Pricing Review – Electricity pricing for a consumer-driven future, Final report,* 18 June 2026.

4.4 Increasing uncertainty is driving greater reliance on intra period adjustment mechanisms

The framework currently manages demand, cost and delivery risk through a package of complementary mechanisms. The AER assesses demand forecasts and expenditure needs when setting fixed ex ante allowances. Fixed allowances and incentive schemes require NSPs to bear some of the consequences of forecast error and provide incentives for efficient forecasting and expenditure planning. Where material uncertainty crystallises after a determination, uncertainty mechanisms including contingent project applications, pass-through provisions and capex reopeners provide targeted flexibility to adjust revenue allowances during a regulatory period.

These mechanisms were designed to operate as targeted exceptions to the ex ante framework, not as a routine feature of cost recovery. However, since 2021, there has been a significant increase in the use of these mechanisms (see Figure 4.1 below), in some cases for purposes that potentially extend beyond their original design. More frequent use of these mechanisms is also likely to have implications for the incentives created by the overarching ex ante regulatory framework. In many cases these mechanisms result in the NSP bearing less of the risk associated with managing its allowance efficiently, and consumers absorb a correspondingly greater share of that risk instead.

This shift warrants closer scrutiny of the:

- mechanisms themselves (as described in more detail in section 4.2, individually and as a package, to test whether they continue to appropriately cover and allocate the range of risks NSPs and consumers now face, and
- processes that govern their use

to test whether they remain fit for purpose given the increasing volume and complexity of applications now being made.

4.4.1 The package of intra period mechanisms

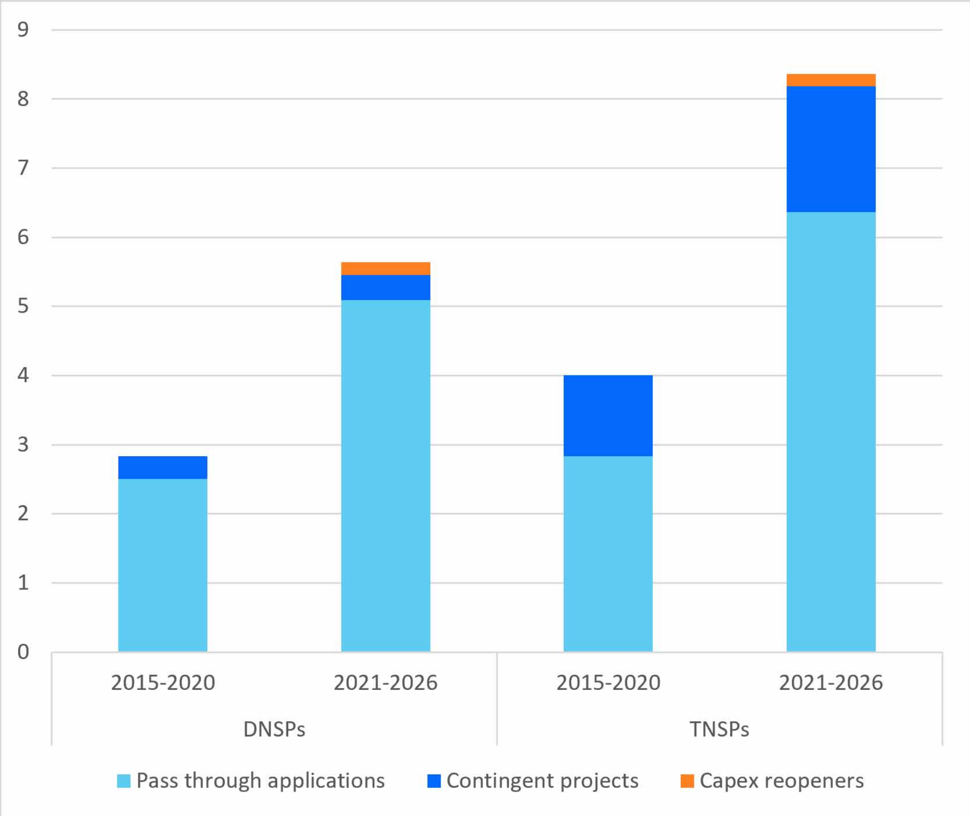
- **Cost pass-through applications** have become more common and are being sought for a wider and evolving range of events generated by the energy transition and its regulatory response.[225]
- **Contingent project applications** are being utilised more frequently by NSPs to fund major transmission and renewable integration investments (See figure 1.1). Growing reliance has risk-allocation implications, with each project moved outside the ex-ante revenue cap and into a contingent project application shifting a greater share of delivery risk onto consumers and eroding the efficiency incentives the revenue cap is designed to preserve.
- **Capex reopeners** previously unused**,** are now being considered as a mechanism for managing large or uncertain investments where neither ex ante forecasts nor contingent projects provide an adequate solution. [226]

Figure 4.1 illustrates this shift by comparing the average number of intra period adjustment applications made by TNSPs and DNSPs in 2015–20 with the number made in 2021–26. The comparison shows that these mechanisms are being used more frequently, and across a broader range of network contexts, than in the previous periods.

225 For example - Victorian DNSPS each submitted cost pass-through applications to recover costs of implementing the AEMC's flexible trading arrangements rule change, a reform designed to unlock greater consumer energy resource integration, showing how regulatory responses to the energy transition are generating new categories of pass-through event beyond natural disasters and other unforeseen physical events. AER, *Victorian DNSPs' cost pass-through applications — flexible trading arrangements rule change*, April 2026.

226 To date, capex reopeners have only been sought twice, Jemena Energy Networks, *Application to reopen for capex*, October 2024, which was subsequently withdrawn, and Transgrid, *Application to reopen for capex - Project EnergyConnect*, February 2026, which remains open.

Figure 4.1: Comparison of average intra period adjustment applications made by NSPs



Source: See AER decisions register here, AER contingent project applications register here and Jemena capex reopener determination here.
Note: 2015-2020 period account for six years, 2021-2026 period accounts for five years and 7 months.

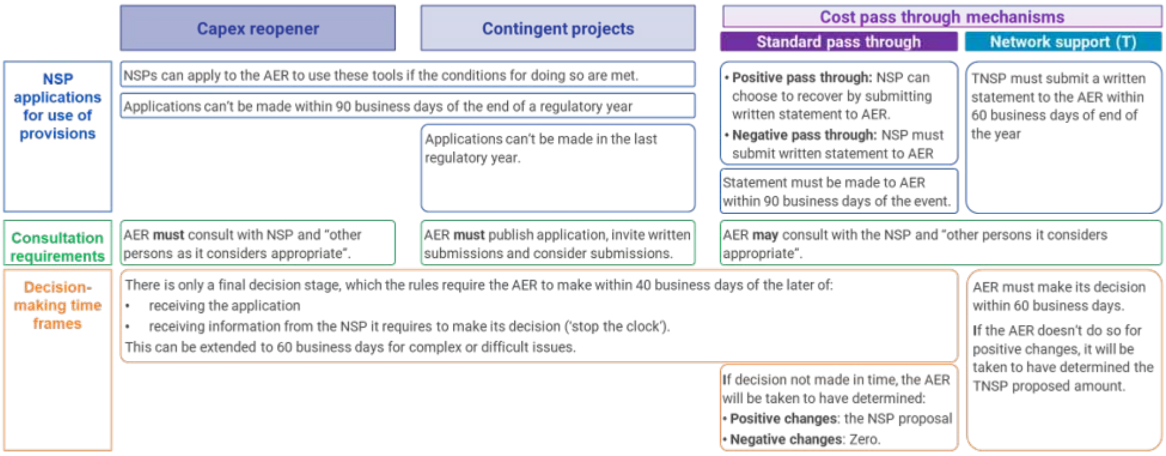
While intra period mechanisms provide flexibility where circumstances materially change, they also alter the allocation of risk between NSPs and consumers. Greater flexibility can support timely and efficient investment, reduce financing costs and allow the framework to respond to uncertainty that cannot reasonably be managed through fixed allowances. Contingent projects are an important example, they can reduce the risk that consumers fund potential projects that prove unnecessary, while also giving NSPs a pathway to recover efficient costs once a defined need is triggered. However, increasing reliance on these mechanisms may weaken incentives for NSPs to manage forecast, procurement and delivery risks, reduce accountability for performance and shift a greater share of risk to consumers.

Through this Review we intend to assess whether the current balance between ex ante regulation and intra period adjustment continues to promote efficient investment and efficient use of electricity services in the long term interests of consumers, or whether increasing reliance on these mechanisms is changing the incentive properties of the framework and the way in which risk is shared between consumers and NSPs.

4.4.2 The framework establishes thresholds, consultation, information and decision-making processes for intra period adjustments

The framework does not only define when allowances may be adjusted during a regulatory period, it also establishes thresholds, consultation, information and decision-making processes for those adjustments. Figure 4.2 provides an overview of these processes.

Figure 4.2: Intra period mechanism decision-making process



Source: AEMC.

These processes were largely designed on the assumption that pass-throughs, contingent projects and reopeners would operate as targeted exceptions to the broader ex ante framework. As reliance on these mechanisms increases, there is a question around how fit for purpose and efficient the processes underlying these mechanisms remain.

As use of these mechanisms increases, their practical operation is beginning to diverge from the assumptions on which their governing processes were designed. Across cost pass-throughs, contingent projects and capex reopeners, a small number of process issues stand out:

- **Materiality thresholds may no longer be well calibrated.** The threshold for a cost pass-through has been lowered, from 1 per cent of Maximum Allowed Revenue to 1 per cent of opex and capex, contributing to a rising volume of applications. We consider this threshold warrants review.
- **Statutory assessment timeframes are increasingly mismatched to the scale of applications.** The 40 business day timeframe for cost pass-throughs and contingent projects were both designed around individual, relatively straightforward matters. As qualifying events and projects have grown more complex, the information required to properly test an application can exceed what these windows were built to accommodate.
- **Stakeholder engagement has not kept pace with the consumer cost at stake.** Submissions on the Victorian DNSPs' flexible trading arrangements cost pass-through application highlighted that these applications can impose material costs on consumers through electricity bills, yet receive limited and inconsistent stakeholder engagement compared to broader regulatory processes, raising concerns about insufficient consumer scrutiny and the cumulative bill impact of multiple pass-through events.[227]
- **Contingent project applications have grown from occasional to routine.** Volumes have risen from typically one or two applications per determination to five or more in recent transmission determinations, raising the question of whether a process built around assessing occasional, individual applications remains well suited to a larger, more concurrent caseload.[228]

227 AER, Determination — *CitiPower, Powercor and United Energy - Unlocking CER Benefits Through Flexible Trading Cost Pass Through*, April 2026, p. 5.

228 Increasing use is also exposing gaps in the current framework: Energy Networks Australia recently submitted a rule change request to enable a TNSP to propose, and the AER to approve, a nominated pass through event as part of a contingent project application — a tool available for expenditure included in a Revenue Proposal but currently unavailable for Contingent Projects under the NER.

- **Common trigger events can create duplicative processes.** Where the same regulatory or policy change affects multiple NSPs, the current framework may require separate applications and assessments for substantially similar issues. This can increase administrative burden for NSPs, the AER and stakeholders, and may reduce the efficiency of consumer scrutiny.
- **Capex reopeners remain the exception, but their purpose and scope may warrant monitoring.** Only two applications have been made to date, Jemena's October 2024 application (subsequently withdrawn) and Transgrid's Project EnergyConnect (PEC) application. The review will monitor the PEC reopener process and stakeholder submission to better understand if changes are needed.

The Review will assess whether existing procedural requirements across each of these mechanisms continue to strike an appropriate balance between timely investment decisions, regulatory scrutiny and consumer protection, and whether existing thresholds, consultation, information and assessment processes remain fit for purpose in an environment characterised by increasing uncertainty and greater use of intra period adjustment mechanisms.

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 underway does the framework appropriately allocate risk between NSPs and consumers?
2. Are the various intra period and ex post adjustment mechanisms appropriately targeted and fit for purpose?

4.5 How should the framework support anticipatory investment?

Network investment decisions often involve significant timing uncertainty. NSPs must decide how far in advance to invest to meet projected demand. Investment that occurs too late may have network reliably implications. Investment that occurs too early may unnecessarily increase costs to consumers. Given demand uncertainty, NSPs should also consider whether their investment approach preserves the flexibility to alter course if the future differs from expectations.[229] NSPs may also be able to deliver networks services more reliably and cost-effectively over the medium and long term by procuring some inputs in bulk, even if ahead of need. This is particularly the case where the global supply chain for electricity assets is stretched or international sellers offer discounts for larger orders.

4.5.1 The value proposition for anticipatory investment

Anticipatory investment poses the reverse problem to the intra period mechanisms discussed in section 4.4. Rather than adjusting allowances after uncertainty has crystallised, it asks consumers to bear a different kind of risk upfront, the risk that the anticipated need does not materialise as expected.

229 Retaining this flexibility often arises through considering the 'option value' of a particular investment. See AER, *Regulatory Investment Test for Distribution application guidelines - 2024 - Version 6*, 2024, pp 102-108: "Option value refers to a benefit that results from retaining flexibility where certain actions are irreversible (sunk), and new information may arise in the future on the payoff from taking a certain action. Option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options are sufficiently flexible to respond to that change".

Box 12: What is anticipatory investment?

NSPs undertake anticipatory investment where expenditure is committed before the timing, scale or preferred solution for a future need is fully confirmed. These needs arise on the basis of demand, generation, or policy decisions. NSPs should make such investments when committing early will reduce overall cost or delivery risk compared with waiting for that need to be fully confirmed. It sits in contrast to an approach where expenditure is triggered once a specific constraint has actually emerged (such as under a contingent project application, see section 4.2).

Examples of anticipatory investment include:

- **Delivering infrastructure ahead of the usual evidence standard**, where demand is forecast to grow rapidly but may not yet meet the threshold required for approval of a related expenditure allowance to, e.g. increase network capacity. This may reflect policy changes or broader shifts in consumer behaviour, such as household electrification.
- **Delivering larger upgrades where this is likely to be more efficient over time.** Where future growth is reasonably expected, it may be more efficient and less disruptive to deliver a larger upgrade once, rather than return later to expand it.
- **Early procurement of key components, equipment or materials.** Funding that is made available for early equipment orders, land acquisition and enabling works before a project has cleared its full regulatory approval process, reducing exposure to supply constraints and allowing land access negotiations to begin earlier.[1][2]
- **Whole of program designation rather than case by case assessment:** Rather than assessing funding project-by-project, there are examples from other jurisdictions where a regulator can pre-identify a cohort of strategically important projects and build a funding pathway around that cohort, extending anticipatory investment to a portfolio of future need rather than a single confirmed project.[3]

[1] The NER already enables facilitates TNSPs recovery of certain early works expenditure for major network projects (AEMC, Contingent Projects — Early Works Rule Change, 2024).

[2] Ofgem's Early Construction Funding allows transmission owners to secure orders for scarce, long-lead-time equipment such as HVDC cables and fund land acquisition, surveys and early construction activities ahead of final approval.

[3] Ofgem pre-designated 26 strategically important transmission projects under Accelerated Strategic Transmission Investment (ASTI) and built a bespoke funding framework around this defined cohort (Ofgem, Decision on Accelerating Onshore Electricity Transmission Investment, 2022).

To date, network investment has proceeded once a relatively clear need for augmentation had been demonstrated. This approach has reflected relatively stable demand growth and comparatively short delivery timeframes.

The energy transition is changing these assumptions. The system is increasingly characterised by large-scale electrification, renewable energy zone development, and battery energy storage investment from individual households through to grid-scale developments, alongside increasing interaction between network and non-network solutions. Many of these developments require investment decisions to be made years before demand or generation outcomes become certain. Longer delivery timeframes reinforce this, and cost and delivery risks including supply chain constraints, labour shortages and extended lead times for critical equipment are having a greater impact on network development. Waiting until demand is fully demonstrated can increase the magnitude of these risks.

This raises broader questions for the Review: Does the current framework facilitate anticipatory investment? Does the regulatory framework appropriately recognise the value of acting early, where doing so reduces future delivery risk, preserves optionality or lowers whole-of-system costs, while continuing to protect consumers from the risks of underutilised or stranded assets?

4.5.2 The framework already enables anticipatory investment, but there may be barriers

The framework does not prohibit anticipatory investment, NSPs can secure funding for forward-looking network augmentation and a separate mechanism exists for TNSPs to support early works ahead of an ISP project's final commitment.[230] In principle, the framework already has the flexibility needed to bring investment forward where doing so would benefit consumers.

In practice, however, this flexibility may not translate into efficient anticipatory investment due to at least two possible barriers:

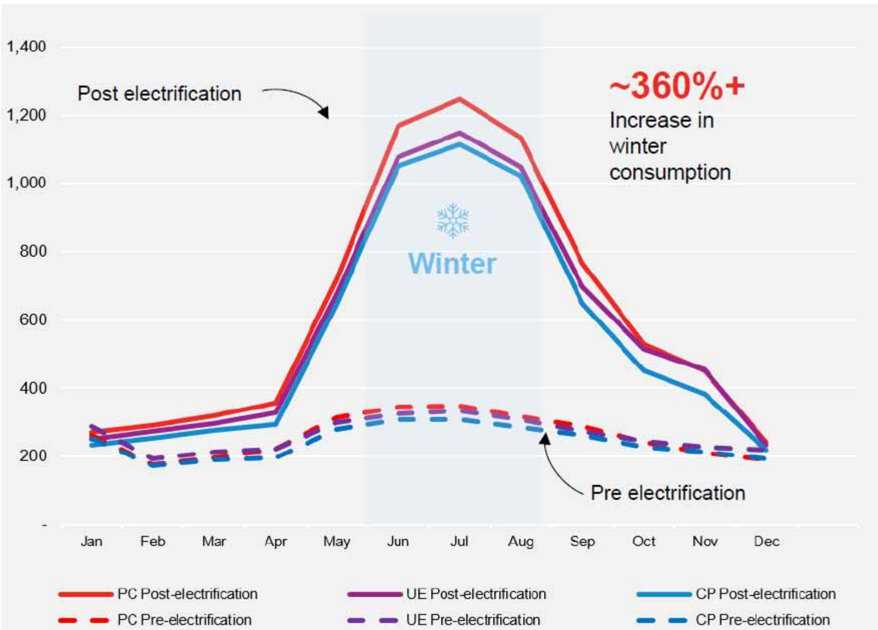
1. *Anticipatory expenditure still needs to be justified against a demonstrated, quantifiable need*, and this is more easily done for a single, well-defined project than for a broad, trend-based program spanning many individual assets, where the case for acting early rests on an observed trend rather than a confirmed constraint at each specific site.
2. *An asymmetry in risk*. Where anticipatory expenditure sits outside an NSP's approved allowance, the NSP bears the downside if that investment is later found inefficient or imprudent. This may discourage NSPs from proposing proactive investment even where it would lower long term costs.

The case study below illustrates how the first of these barriers can operate in practice.

Box 13: Case study - Electrification and low voltage network investment in Victoria

The rapid electrification of the economy provides an example of where anticipatory investment may be in the interests of consumers. CitiPower, Powercor and United Energy's (CPU) analysis of smart meter data across approximately 27,000 recently electrified Victorian customers found winter consumption increasing by more than 360 per cent post-electrification, with an increase in the average daily winter peak demand of 50 to 60 per cent.

Figure 1: Winter energy usage post electrification (monthly net consumption in kWh)



Electrification is likely to drive sustained, generalised demand growth rather than growth isolated

230 In 2024 the AEMC made a final rule for its *Bringing Early Works Forward to Improve Transmission Planning rule change*, allowing TNSPs to submit an early works contingent project application to the AER.

to specific parts of a network. Networks may be able to more efficiently respond to electrification through a coordinated upgrade program rather than investing site by site as constraints emerge. It can be more cost-effective to coordinate the necessary labour and physical inputs over a larger project, rather than through bespoke procurements for each individual location. Bringing investment forward, therefore, could also smooth delivery and reduce overall costs to consumers.

CPU has indicated that the need to demonstrate confirmed, location-specific demand may act as a barrier to anticipatory investment. This may lead to less efficient procurement decisions than under a more proactive approach, which could smooth delivery and lower costs over time.

Consistent with the capex criteria in the National Electricity Rules, that a forecast must reflect efficient costs, the costs a prudent operator would require, and a realistic expectation of demand,[1] the AER's final decision for Powercor did not accept the anticipatory, coordinated-upgrade approach CPU proposed for augmentation expenditure.

Source: CitiPower, Powercor, and United Energy - anticipatory investment case study provided to the AEMC. Analysis includes detected electrified customer cohorts from CitiPower (4,411), Powercor (11,366), and United Energy (11,071) based on pre- and post-electrification AMI data.

[1] Clause 6.5.7(c), 6.5.7(a) requires the AER to accept a DNSP's forecast capex only if satisfied that, in total, it reasonably reflects: (1) the efficient costs of achieving the capex objectives; (2) the costs that a prudent operator would require to achieve the capex objectives; and (3) a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the capex objectives.

A central challenge for the framework is how it should allocate the risks associated with anticipatory investment. Anticipatory investment can allow NSPs (and ultimately consumers) to benefit from economies of scale and access dynamic efficiencies by securing materials, contractor capacity or equipment before costs increase further or supply becomes constrained. Conversely, those same investments may result in over-procurement or underutilised assets if expected demand, generation development or policy outcomes do not ultimately materialise, leaving consumers to bear the associated costs.

How timing and delivery risk associated with anticipatory investment is shared currently depends on how the expenditure is treated under the ex ante framework. Where anticipatory expenditure is included in an NSP's approved capital expenditure allowance, consumers may ultimately bear much of that risk through the existing cost recovery arrangements. Where the expenditure is not included in forecast allowances, NSPs may bear a greater share of the risk through expenditure incentive arrangements and the consequences of overspending relative to approved allowances if the overspend is deemed inefficient or imprudent by the AER. A worst-case outcome for an NSP is to undertake anticipatory investment it considers in consumers' long-term interests, then have that expenditure excluded from the RAB as inefficient or imprudent and potentially incur a CESS penalty for exceeding its overall capex allowance.

Defined adjustments to the CESS moderate this allocation of risk. Where an ex post review excludes incurred capex from the RAB, the AER may also exclude that expenditure from the CESS calculation. This ensures an NSP does not bear the cost of more than 100 per cent of expenditure found to be inefficient or imprudent, while consumers remain shielded from funding investment later found not to meet the efficiency and prudency tests. In practice, the AER has adjusted the application of the CESS to account for any capital removed in an ex post review.[231]

Even with these adjustments, the underlying allocation of timing and delivery risk between NSPs and consumers remains a function of how the framework treats anticipatory expenditure at the outset. This raises a broader question for the Review. Does the current framework appropriately balance:

231 AER, *Draft Decision Attachment 9 - Capital expenditure sharing scheme - Ergon Energy - 2025-30 Distribution revenue proposal*, September 2024, p. 5.

- the value of acting early, where doing so reduces future delivery risk, preserves optionality or lowers total costs over time
- protecting consumers from the risks of excessive or untimely investment.

The Review will assess whether the framework appropriately balances these competing risks and promotes long term consumer interests.

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?
2. Are there aspects of the regulatory framework that act as a barrier to efficient anticipatory investment? Please provide evidence or case studies.

4.6 The RoRI framework compensates NSPs for systematic risk

The RoRI is the instrument used by the AER to determine the level of systematic risk NSPs face. It compensates investors for the systematic risks associated with financing long-lived network infrastructure, while supporting efficient investment and protecting consumers from paying more than necessary for network services.[232] In contrast, business and project-specific risks are generally managed through the mechanisms discussed in section 4.4.

4.6.1 TNSPs and DNSPs may be facing increasingly diverse risks

A singular RoRI applies to both TNSPs and DNSPs[233] and is based on the view tha despite their different roles in the network, both types of businesses face a similar operating environment characterised by the same economy wide systematic risk. This reflects the view that the risks distinguishing transmission from distribution are largely diversifiable, firm or sector specific risks.

The energy transition may be testing the assumption that transmission and distribution businesses face broadly comparable risk profiles:

- TNSPs are increasingly responsible for delivering large-scale greenfield transmission projects associated with the ISP, renewable energy zones and jurisdictional infrastructure programs. As discussed in chapter 1, these projects are characterised by long development timeframes, significant capital commitments, extensive stakeholder engagement requirements, complex approval pathways and greater exposure to construction and delivery risks.
- DNSPs may face a different set of challenges. Electrification, declining residential and small commercial gas demand, flexible demand due to the proliferation of CER and the transition toward distribution system operation functions may expose DNSPs to increasing uncertainty regarding demand growth, utilisation, new roles and responsibilities and local network investment needs.[234] These risks may be more dispersed and dynamic than those historically faced by transmission businesses and may vary considerably between jurisdictions and network areas.

232 Division 1B of the NEL sets out the requirements the AER must follow when making a rate of return instrument.

233 Section 18J(2) of the NEL specifically provides that the RoRI must apply the same methodology to all NSPs.

234 Final advice to Ministers to progress M3/P5priority of the National CER Roadmap: *Redefining Roles and Responsibilities for Power System and Market Operations in a High CER Future: Final Advice to Ministers to Progress M3/P5 Priority of the National CER Roadmap*, December 2025.

This raises a threshold question for the Review. To the extent diverging risks between TNSPs and DNSPs are systematic, should they be compensated through the RoRI, or can they continue to be addressed through other regulatory tools, such as intra period adjustment mechanisms?

For example, the construction and delivery risk associated with TNSP greenfield projects may be more appropriately managed on a project-specific basis, through mechanisms such as contingent projects, cost pass-throughs or other in-period adjustment tools, rather than through a change to the systematic risk allowance in the RoRI itself.[235] The evolving role of DNSPs may raise a different kind of question. As DNSPs transition toward distribution system operator (DSO) functions, coordinating CER, managing two-way power flows, and taking on new network planning and operational responsibilities, the nature of the risk they face may be shifting in a way that is less project-specific and more structural.

Where diverging risks are genuinely systematic in nature, a question arises as to whether the NEL prescribed RoRI framework, which requires a common methodology across transmission and distribution, remains fit for purpose.

4.6.2 Can a common RoRI methodology practically accommodate diverging systematic risk

If the AER considered systematic risk profiles had diverged significantly enough to warrant separate rates of return for TNSPs and DNSP, they would continue to be restricted by the NEL's requirement to develop and apply a RoRI that uses a common methodology for all NSPs.[236]

The practical question for the Review is whether this requirement leaves the AER with sufficient flexibility to respond if transmission and distribution systematic risk profiles were to diverge materially, or whether the NEL's requirement for the same methodology would itself need to change before any differentiation could occur.

4.6.3 There are implementation challenges to setting different rates of return

If a conceptual case for differentiating transmission and distribution systematic risk were established, practical constraints in the current methodology would make a differentiated instrument difficult to implement. The two largest practical constraints are:

- *Calculating the equity beta*: The AER's domestic comparator set for equity beta has shrunk from nine listed Australian network businesses to just one, APA Group, itself an imperfect comparator given its low proportion of regulated revenue. This has forced reliance on international comparators that the AER acknowledges are only weakly correlated with domestic estimates.[237] Splitting this already thin sample into separate transmission and distribution comparator sets would leave few, if any, meaningful domestic comparators for either.
- *Calculating the cost of debt*: The AER considered but rejected a weighted trailing average approach targeted at businesses raising materially larger debt volumes in shorter periods, a concern raised most acutely by TNSPs, on the basis that any threshold for identifying affected businesses would be arbitrary, add unnecessary complexity, and create incentives for strategic behaviour around the trigger.[238] A structural TNSP/DNSP split in the cost of debt methodology

235 In response to Transgrid's submission arguing that greenfield transmission projects are exposed to additional systematic risk during construction due to their scale and complexity, the AER found it unclear how much, if any, extra systematic risk is associated with greenfield projects, and noted that Transgrid had not quantified this incremental systematic risk exposure in its submission (AER, *Draft 2026 Rate of Return Instrument – Explanatory Statement*, May 2026, pp. 41–42).

236 Section 18J(2) of the NEL specifically provides that the RoRI must apply the same methodology to all NSPs.

237 AER, *Draft 2026 Rate of Return Instrument – Explanatory Statement*, May 2026, pp. 36-38)

238 AER, *Draft 2026 Rate of Return Instrument – Explanatory Statement*, May 2026, p. 51

would face a similar design problem: any bright-line distinction between the two categories of business would need to draw a threshold that is likely to be similarly arbitrary and similarly exposed to strategic behaviour around its edges.

These practical challenges do not mean that TNSP and DNSP risk profiles will not continue to change, or that any such change will not eventually become material. If emerging differences primarily reflect project-specific, operational or delivery challenges, they may continue to be more appropriately managed through expenditure allowances, incentive schemes, intra period adjustment and financeability mechanism that make up the risk-reward package. If, however, the transition is causing the systematic risk exposure of transmission and distribution businesses to diverge in a sustained and material way, questions may arise regarding whether the current framework provides sufficient flexibility to reflect those differences, while maintaining regulatory certainty and consistency to ensure stable price paths for consumers.

We also note that the Commission cannot make changes to the requirements set out in the NEL. Any changes to the NEL would need to be agreed and implemented by Energy Ministers. We consider this Review is the appropriate place to consider this aspect of the NEL to ensure the risk allocation and compensation framework operates as a cohesive package into the future. Based on our further consideration of this issue, we may make recommendations for the NEL to change.

Question 11: Does the RoRI enable appropriate compensation for risk within the context of the regulatory package as a whole?

1. Are emerging transition-related risks systematic or business-specific in nature?
2. Are TNSPs and DNSPs facing increasingly different risk profiles and, if so, are those differences relevant for the RoRI?
3. Does the current RoRI framework provide sufficient flexibility to reflect changes in systematic risk over time?

5 Making our recommendations

When considering the issues within this Review, the Commission considers a range of factors.

This chapter outlines:

- issues the Commission must take into account
- our proposed assessment criteria

We would like your feedback on the proposed assessment framework.

5.1 The Commission must act in the long-term interests of consumers

In conducting reviews, the Commission must have regard to the relevant energy objectives.[239] For this Review, the relevant energy objective is the NEO.

The NEO is:[240]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.

5.2 We will also take other factors into account

In addition to the NEO, the Commission may also take other factors into account when relevant to our decisions, including:

- the **form of regulation factors** in section 2F of the NEL,[241] when making a recommendation that specifies an electricity network service as a direct control network service
- the **revenue and pricing principles** in section 7A of the NEL,[242] when making a recommendation that regulates the revenues earned, or prices charged by owners, controllers or operators of a transmission system or a distribution system, for the provision by them of services that are the subject of a determination.[243]

The form of regulation factors are:

> (a) the presence and extent of any barriers to entry in a market for electricity network services;

239 Section 32 of the NEL.

240 Section 7 of the NEL.

241 Section 88A of the NEL.

242 Section 88B of the NEL.

243 NEL schedule 1 items 15, 16(1), 25 and 26.

(b) the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider;

(c) the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market;

(d) the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user;

(e) the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service;

(f) the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be);

(g) the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.

The revenue and pricing principles are:

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in:

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes-

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—

(a) in any previous—

(i) as the case requires, distribution determination or transmission determination; or

(ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

(b) in the Rules.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

5.3 We propose to assess this Review using these five assessment criteria

5.3.1 Our methods to analyse the policy issues

Considering the NEO and the issues we have identified, the Commission proposes to use the set of criteria outlined below to assess its recommendations. These assessment criteria reflect the key potential impacts – costs and benefits – of potential Review recommendations. We consider these impacts within the framework of the NEO.

The Commission's regulatory impact analysis may use qualitative and/or quantitative methodologies. The depth of analysis will be commensurate with the potential impacts of any recommendations. We may refine these methodologies as this Review progresses, including in response to stakeholder submissions.

Consistent with good regulatory practice, we will assess all viable policy options — including not proposing any changes or considering solutions outside of the regulatory framework — using the same set of assessment criteria and impact analysis methodology where feasible.

5.3.2 Assessment criteria and rationale

Our proposed assessment criteria and rationale for each is as follows:

- **Outcomes for consumers:** Promoting the long term interests of electricity consumers is the overarching objective of the regulatory framework and as consumers become more active in the electricity market, it is becoming increasingly important to ensure that the market is delivering the outcomes consumers expect. We intend therefore to consider the extent to which reform options identified through the Review will promote long term consumer interests, including by providing consumers:
  - access to the services that they want and need
  - more efficient price signals, better incentives and opportunities.
- **Principles of market efficiency:** The regulatory framework is intended to promote economic efficiency in the provision and use of electricity services. As the energy transition progresses, market efficiency is likely to be increasingly challenged, including due to increased risk and uncertainty. Risk allocation and concepts of efficiency are likely to be key to considering appropriate regulatory flexibility and risk sharing. We intend to consider the extent to which the reform options identified through the Review will:

  - promote productive, allocative and dynamic efficiency in the provision and use of network and other electricity services
  - provide NSPs appropriate incentives to deliver the services that consumers want and to pursue expenditure and operational efficiencies
  - provide for an efficient allocation of risk and a balanced risk/reward package.
- **Innovation and flexibility:** As the energy transition progresses, it will be increasingly important for the regulatory framework to support innovation and flexibility. We intend to consider the extent to which the reform options identified through the Review will:
  - support innovation and provide for the benefits of innovation to be passed through to consumers
  - be sufficiently flexible to accommodate market, technological, policy, climate and other changes.
- **Emissions reduction:** Network regulation can have a direct impact on consumer and NSP behaviour and the achievement of emissions reduction targets. At the distribution level this can include increasing use of and incentives for investment in CER. At the transmission level this can include increasing incentives and/or removing barriers to major projects required to meet emissions reduction targets. We intend to consider the impact that any reform options identified through the Review may have on the achievement of jurisdictions' emissions reduction targets.
- **Principles of good regulatory practice:** Any potential changes to the regulatory framework arising as a result of reform options identified in the Review will need to follow principles of good regulatory practice. The simplicity and stability of the framework will be key considerations when assessing the implementation feasibility of reform options. We intend therefore to consider the extent to which reform options identified through the Review would:
  - provide for a predictable and stable regulatory framework
  - promote transparency and simplicity for all stakeholders
  - support flexibility and resilience in the regulatory framework by employing a principles-based approach, except where prescription is necessary
  - align with the broader direction of reforms.

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?

A Application of our prioritisation framework

This Appendix sets out our assessment of the issues proposed for further investigation against our prioritisation framework. It also includes our assessment of a small number of other issues that we considered as part of our scoping work but are not proposing to explore further. Our prioritisation framework is shown below in Table A.1.

Table A.1: Prioritisation framework - Criteria and rating scale

Criteria	Description	Priority Indicator
Materiality	How significant is this issue and how strong is the evidence base? How much do consumers stand to benefit from addressing this issue?	**High** (3/3)– consumers stand to significantly benefit and there is evidence that this is an issue. **Medium** (2/3)– the consumer benefit or evidence is unclear. **Low** (1/3)– the consumer benefit is low and there is evidence to support that this is not a substantive issue.
Implementation feasibility	Can solutions be implemented by the AEMC through NER changes, or do they require agreement and coordination from other actors (e.g. Energy Ministers)? If coordination is required, how difficult will it be? Are there other implementation challenges?	**High** (3/3)– consumers stand to significantly benefit and there is evidence that this is an issue. **Medium** (2/3)– the consumer benefit or evidence is unclear. **Low** (1/3)– the consumer benefit is low and there is evidence to support that this is not a substantive issue.
Other processes	Is there another rule change process already underway, or are there formal review processes already established, that are better placed to review this aspect of the framework and efficiently address the identified issue?	**Not addressed** (3/3)– There is no other process underway or formal review mechanism. **Partially addressed** (2/3)– part of the issue is addressed by another process. **Addressed** (1/3)– another process is established to consider this issue/or has considered this issue recently.
Separability	Is this an issue that is difficult to consider in isolation such that it should be considered through a holistic review of this nature? Or can it be separated and progressed through a stand-alone process that would likely lead to faster resolution of the issue (e.g. a rule change or other process)?	**Not separable** (3/3)– this issue is difficult to consider in isolation with strong interactions with other parts of the framework. **Partially separable** (2/3)– the issue is largely separable and interactions with other parts of the framework are fewer or more minor. **Separable** (1/3)– this is a separable issue with limited interactions with other parts

Criteria	Description	Priority Indicator
		of the framework.

A.1 Issues that we propose exploring further and rationale for prioritisation

Table A.2: Efficiency of the revenue determination process

Criteria	Description	
Description of issue	See section 2.3	
Materiality	Medium	This issue is important from a regulatory burden/cost perspective, with NSPs, consumers and the AER the potential beneficiaries of any simplification/streamlining of the regulatory determination process. It is difficult to know at this stage how material the potential cost savings are likely to be and how much consumers would stand to benefit from addressing this issue. However, it is worth noting that the benefit may be lower than some of the other potential areas for policy reform. This is because regulatory costs make up a relatively small proportion of an NSP's revenue requirement.
Implementation feasibility	High	Solutions could be implemented by the AEMC through changes to the NER and does not require coordination with other parties.
Other processes	Not addressed	There is no rule change or other review process underway that will consider this issue. While the AER has in the past used its Better Resets Handbook to provide for a more streamlined review process, there are limits to what can be achieved by the AER given a lot of the regulatory process is set out in the NER.

Criteria	Description	
Separability	Partially separable	It may be possible to separately consider how to streamline or otherwise improve the efficiency of the regulatory determination process. However, there are strong interconnections between process efficiency and outcomes. This issue would therefore ideally be considered as part of a holistic review.
Consider as part of Review	Yes	

Table A.3: Outcomes of the revenue determination process

Criteria	Description	
Description of issue	See section 2.4	
Materiality	High	The process for setting NSPs revenue allowances has a strong bearing on the overall amount that NSPs' consumers pay. Any improvements in the accuracy of the allowance setting process could result in material benefits to consumers.
Implementation feasibility	High	Changes to the revenue determination process can be made through the NER and AER guidelines.
Other processes	Not addressed	There is no current process examining this issue.
Separability	Not separable	The revenue determination process is intrinsically linked with other parts of the framework including incentive schemes such as the CESS and EBSS. This issue is not easily separable.
Consider as part of Review	Yes	

Table A.4: Ensuring consumer interests are effectively represented and reflected in regulatory determinations

Criteria	Description	
Description of issue	See section 2.5	
Materiality	Medium	Consumer preferences can change key trade-offs in determinations (for example, cost vs. reliability), and it is therefore important that the framework allows consumer preferences to be reflected. The extent to which consumer preferences are reflected in determinations can also affect consumer bills (in both directions).
Implementation feasibility	High	Changes to the revenue determination process can be made through the NER and AER guidelines.
Other processes	Not addressed	There is no current process examining this issue.
Separability	Partially separable	It may be possible to separately consider how consumer views are incorporated into the determination process and arrive at a solution that is separable from other issues. However, solutions may be highly dependent on other issues being considered through this Review, such as other potential changes to the revenue determination process. This issue would therefore ideally be considered holistically.
Consider as part of review	Yes	

Table A.5: Incentives between capex and opex

Criteria	Description	
Description of issue	See section 3.3	
Materiality	High	This issue is significant, given

Criteria	Description	
		the changing nature of network services. Ensuring NSPs are appropriately incentivised to efficiently provide network services, irrespective of whether it involves capex or opex, could therefore have a material impact on consumers. There are multiple data points that suggest there are barriers in the current framework.
Implementation feasibility	High	Solutions could be implemented through changes to the NER and AER guidelines.
Other processes	Not addressed	There is no rule change or other review process underway that will consider this issue. The AER has the capability to review individual incentive schemes that may have a bearing on capex vs opex incentives, but there is no other current process that reviews the implicit incentives created by the building block model and the range of factors that impact the capex-opex asymmetry.
Separability	Not separable	This issue would be difficult to consider in isolation because any solutions that are identified could have implications for other parts of the regulatory framework. It should therefore be considered as part of a holistic review.
Consider as part of Review	Yes	

Table A.6: DSO incentives

Description of issue	See section 3.4	
Materiality	Medium-High	The evolution of DNSPs into DSOs is a significant development and more active

		management of CER in the distribution system is likely to have substantial benefits for consumers. The new DSO role may require new approaches to incentives, however the extent of this requires further analysis.
Implementation feasibility	Medium	Solutions could be implemented through changes to the NER and AER guidelines.
Other processes	Not addressed	This Review was identified by the CER Taskforce as the most appropriate process to consider this piece of work.
Separability	Not separable	The consideration of the potential need for specific DSO incentives is inter-related with the performance of other incentive schemes under the regulatory framework. This issue would ideally be considered holistically.
Consider as part of Review	Yes	

Table A.7: Driving 'efficient' network utilisation by NSPs

Criteria	Description	
Description of issue	See section 3.5	
Materiality	High	'Efficient' utilisation is one of the key policy levers available to reduce per unit prices for consumers, however measurement limitations make the current scale of the problem difficult to assess. The materiality of this issue is likely to grow as CER uptake increases and consumers can become more price responsive. Given the debate around what 'efficient' utilisation means in a transitioning system, we consider it is important to

Criteria	Description	
		consider this threshold question first.
Implementation feasibility	Medium	Reform could be implemented through the NER (eg pricing and/or incentive mechanisms) or by the AER (eg changes in the form of control for DNSPs).
Other processes	Partially addressed	The AER has existing capability to change the form of control for DNSPs and the Pricing Review has already considered the use of pricing to improve utilisation and utilisation incentives to an extent. A key question for the ENRR will be if anything else is needed to support 'efficient' network utilisation.
Separability	Not separable	Any of the potential mechanisms to promote 'efficient' utilisation (noting that we first have to approach the 'efficiency' question) would have significant implications for the rest of the framework and so this issue is challenging to consider in isolation. Incentivising 'efficient' utilisation in isolation risks unintended consequences for cost and/or reliability depending on how 'efficient' is defined.
Consider as part of Review	Yes	

Table A.8: Network innovation

Criteria	Description	
Description of issue	See section 3.6	
Materiality	Medium	Research and development and innovation are important to achieving dynamic efficiency and improving consumer outcomes over time.

Criteria	Description	
		Innovation by NSPs is primarily supported by the DMIA, which supports modest expenditure on innovation but may not address the inability of NSPs to capture all the upside of innovation.
Implementation feasibility	Medium-high	Solutions can be implemented through the NER and AER guidelines. However, other complementary reforms may also be needed outside the NER - such as broader R&D and commercialisation support - to comprehensively address this issue.
Other processes	Not addressed	There are no other processes considering this issue within the NER framework.
Separability	Not separable	This issue is difficult to consider in isolation as reform options are likely to include consideration of existing incentive mechanisms such as the DMIA. The impact of other incentive schemes such as the CESS and EBSS are also likely to require consideration.
Consider as part of Review	Yes	

Table A.9: Risk allocation and compensation through intra-period mechanisms and the form of control

Criteria	Description	
Description of issue	See section 4.3	
Materiality	High	The allocation of risk has significant implications for both NSPs and consumers and the energy transition is changing the nature of risks that must be accounted for and shared. Consumers will be worse off if NSPs bear too much or too little risk – getting the risk allocation and

Criteria	Description	
		compensation balance right is fundamental to achieving positive consumer outcomes through the transition.
Implementation feasibility	High	The majority of changes could be implemented the NER and AER guidelines.
Other processes	Not addressed	There is not currently another process underway to examine these issues.
Separability	Not separable	There are different ways in which the framework can allocate and compensate for risk. These should be considered together as a cohesive 'risk-reward package' rather than in isolation. There is a strong case for considering this issue as part of a holistic review of the framework.
Consider as part of Review	Yes	

Table A.10: Anticipatory investment

Criteria	Description	
Description of issue	See section 4.3.3	
Materiality	Medium	To the extent that anticipatory investment improves efficiency and timeliness of delivery there are likely to be strong consumer benefits. A key question that needs to be investigated are the changes in risk allocation and relatedly, the potential costs to consumers. The extent of this issue requires further investigation.
Implementation feasibility	High	Solutions could be implemented through changes to the NER and AER guidelines.
Other processes	Not addressed	No existing process is looking at the issue.
Separability	Not separable	This issue closely interacts with both the ex ante nature of

Criteria	Description	
		the revenue setting process as well as other intra-period adjustment mechanisms that introduce ex post elements. As such it should be considered as part of ENRR in the context of the broader risk-reward package for networks.
Consider as part of Review	Yes	

Table A.11: Flexibility developing the rate of return instrument

Criteria	Description	
Description of issue	See section 4.3.4	
Materiality	Medium	The RoRI compensates NSPs for systematic risk. Materiality therefore depends on whether the changing risks facing TNSPs and DNSPs are genuinely systematic and warrant differentiated compensation through the RoRI. On the other hand, business/project-specific risks are better addressed through other parts of the risk-reward framework. For example, TNSPs may face materially different investment and delivery risk than DNSPs as a result of the scale and pace of transmission build required for the energy transition, whereas DNSPs' risk profile may be changing for different reasons (e.g. DER integration, electrification and new roles and responsibilities as DSO's). Even if these differences are systematic, it is unclear whether a differentiated RoRI would produce a materially different outcome, given the methodological challenges in isolating and quantifying any

Criteria	Description	
		additional systematic risk specific to TNSPs or DNSPs.
Implementation feasibility	Medium	Substantive changes in approach to systematic risk between TNSPs and DNSPs may require changes to the NEL, which would need to be agreed by all Energy Ministers. If the increased risks facing TNSPs or DNSPs are diversifiable (business/project specific) they would not warrant compensation through the RoRI, and would instead need to be addressed, if appropriate, through other elements of the risk-reward package (e.g. cost pass-throughs, contingent projects, or ex post review). This would not require change to the NEL's RoRI provisions.
Other processes	Not addressed	There is no other process to consider whether the RoRI as part of the risk reward package. The ENRR (or another AEMC review) is likely the appropriate place for the AEMC to assess the flexibility of the RoRI framework and the risk reward package and recommend/make changes to the NEL and NER if required.
Separability	Not separable	The appropriateness of the rate of return framework needs to be considered in the context of risk allocation mechanisms and other compensation tools. It is difficult to assess the appropriateness of the framework in isolation.
Consider as part of Review	Yes	

A.2 Other issues considered but not prioritised and rationale for non-prioritisation

Table A.12: Delivery incentives

Criteria	Description	
Description of issue	The current framework strongly rewards efficient expenditure and can encourage NSPs to minimise or defer investment, which may be efficient where early investment would impose unnecessary costs on consumers. However, as NSPs take on new responsibilities for system security, DSO capability and major project delivery, delayed delivery of critical projects may increasingly create system-wide costs that are not fully reflected in current incentives.	
Materiality	Medium	Delayed delivery of critical transition projects can have a material impact on consumer outcomes. However, there is limited evidence that this is an issue that is not addressed through existing processes.
Implementation feasibility	High	Changes could be implemented through the NER and AER guidelines.
Other processes	Partially addressed	The AEMC's *Transmission Planning and Investment Review* (TPIR) considered and ruled out introduction of a delivery incentive for major transmission projects. The AEMC's *Security framework enhancements* rule change may consider delivery incentives for system security investment.
Separability	Partially separable	Specific delivery incentives could be developed outside of the Review, but there is likely some interaction between these incentives and the broader framework. We intend to manage this through close collaboration with the AER.
Consider as part of Review	**No -** The evidence for this issue is unclear and issues can or have been largely addressed through other processes.	

Table A.13: Has the AER set an appropriate rate of return over time?

Criteria	Description	
Description of issue	The AER's rate of return is set through a detailed RoRI review consultation process, and most stakeholders do not consider there is compelling evidence that the AER has systematically inappropriately estimated returns over time. Some methodological choices, which are within the AER's discretion, remain contested. This includes choices around the equity beta and the trailing average return on debt, which are currently being considered through the AER's RoRI review.	
Materiality	Medium	Any changes to how the rate of return is calculated could have a material impact on NSP revenue allowances, consumer prices and investment. However, we consider this issue relates to 1) methodological decisions made by the AER, which the AER is extensively consulting on as part of its RoRI review and 2) ultimately the AER determines the most appropriate methodological approach based on a range of factors, including implementation considerations.
Implementation feasibility	Low	Changes in approach are not within the AEMC's rule making remit and would need to be implemented either: • by the AER , or • through greater prescription in the NEL which would need to be agreed by all Energy Ministers.
Other processes	Addressed	The AER is currently reviewing the RoRI and is required to consider a range of stakeholder concerns regarding the equity beta, the trailing average of debt and other related concerns through

Criteria	Description	
		the process.
Separability	Separable	These issues can be considered separately from other issues and progressed through the AER's current RoRI review, which would likely lead to faster resolution of the issues.
Consider as part of review	**No -** The AEMC has limited remit to make effective changes and the issue is being considered through the AER's RoRI review.	

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BST	Base-step-trend
Capex	Capital expenditure
CEPA	Cambridge Economic Policy Associates
CER	Consumer energy resources
CESS	Capital expenditure sharing scheme
Commission	See AEMC
CSIS	Customer service incentive scheme
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DSO	Distribution system operator
EBSS	Efficiency benefit sharing scheme
ESIS	Export service incentive scheme
ICT	Information and communications technology
ISP	Integrated system plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NNO	Non-network options
NSP	Network service provider
Opex	Operating expenditure
RAB	Regulatory asset base
RIT-D	Regulatory investment test for distribution
RiT-T	Regulatory investment test for transmission
RoRI	Rate of return instrument
STPIS	Service target performance incentive scheme
TNSP	Transmission network service provider
Totex	Total expenditure
WACC	Weighted average cost of capital