Australian Government

AUSTRALIAN ENERGY REGULATOR

Framework and Approach papers 2029–34

Ausgrid, Endeavour Energy, Essential Energy, Evoenergy, Power & Water Corporation and TasNetworks

Consultation on matters for amendment or replacement

November 2026

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1 Executive summary

The Australian Energy Regulator (AER) regulates electricity transmission and distribution networks in all states and territories except Western Australia. We exist to ensure energy consumers are better off, now and in the future.

Regulated network service providers (NSPs) must periodically apply to us for a determination of the revenue they may recover from consumers using their networks. In January 2028, we will receive proposals for the period 1 July 2029 to 30 June 2034 (the 2029–34 period) from 6 distribution network service providers (DNSPs): Ausgrid, Endeavour Energy (Endeavour), Essential Energy (Essential), Evoenergy, Power & Water Corporation (PWC) and TasNetworks. We will also receive a proposal from TasNetworks in its capacity as a transmission network service provider (TNSP).

The Framework and Approach papers (F&As) are the first formal opportunity to shape how we will approach key elements of these proposals, and our determinations on them. For both DNSPs and TNSPs, the F&A covers incentive schemes, application of the Expenditure Forecast Assessment Guidelines and the basis for depreciation used to establish the next opening regulatory asset base (RAB). For DNSPs, it also covers classification of the distribution services that our determinations will cover, the forms of control and supporting formulae that will apply to those services, and the pricing treatment of dual function assets.

We are asking stakeholders to identify the F&A matters that warrant closer examination before NSPs lodge their proposals in January 2028. After considering submissions, we will confirm the scope of our F&A review in December 2026, test proposed positions during 2027 and publish final F&As in July 2027.

What we are asking from you:

- Tell us which F&A matters you think we should review, and why.
- Help guide our early thinking by sharing your thoughts on the consultation questions asked throughout this paper.

2 Introduction

The Framework and Approach paper (F&A) is the first formal step in preparing for the 2029-34 determinations. It gives NSPs, consumers and their advocates early visibility of the regulatory settings we expect to apply before NSPs finalise their proposals.

We made the current F&As for these NSPs in July 2022, for the 2024–29 period. Each NSP has asked us to amend or replace the service classifications that have applied in 2024-29 with new and/or additional classifications for 2029–34. Matters nominated by an NSP are automatically within the scope of our review.

This consultation seeks views on any additional matters you think we should review, as well as early substantive views to inform our consideration of the matters discussed in this paper.

The electricity network regulatory framework is under review

The Australian Energy Market Commission (AEMC) is reviewing the electricity network regulatory framework as the National Electricity Market transitions to net zero, including service classification, incentives and regulatory processes.

The Electricity Network Regulation Review (ENRR)[1] will run in parallel to, but is not fully aligned with, the prescribed timing of the 2029–34 F&A and determination processes.

We will apply the National Electricity Rules (NER) in force at each decision point and accommodate any relevant changes arising from the ENRR as they take effect, but we cannot make a binding or constraining decision in the F&A or our determinations on the assumption that a proposed recommendation will prevail, or that a particular rule change will be made.

- In July 2027, we will publish our final F&As under the NER in force at that time.
- In January 2028, NSPs will submit their proposals under the NER as in force at that time.
- Around September 2028, we will make draft determinations for the 2029–34 period under the NER as in force at that time.
- In April 2029, we will make our final determinations under the NER as in force at that time.

The NER already provide considerable flexibility for us to make decisions in the long-term interests of consumers, and we will continue to use that flexibility.

[1] Electricity Network Regulation Review – Package 1 | AEMC; Electricity Network Regulation Review - Package 2 | AEMC

2.1 What the F&A covers

The F&A covers a defined set of matters under the NER.[2]

The table below shows which matters apply to DNSPs and TNSPs, and the type of F&A action required.

Table 1 F&A coverage by provider type

F&A matter	Action in F&A	DNSP	TNSP
Application of the STPIS, EBSS, CESS and DMIAM	Proposed approach	✓	✓
Application of the EFA Guidelines	Proposed approach	✓	✓
Depreciation basis for the next opening RAB	Proposed approach	✓	✓
Forms of control mechanism	Decision	✓	—
Dual function assets: pricing framework	Decision	✓	—
Distribution service classification	Proposed approach	✓	—
Control formulae	Proposed approach	✓	—
Additional DNSP schemes: CSIS, DMIS and ESIS	Proposed approach	✓	—

Note: Dual function asset pricing is not considered for PWC: NER (NT) version 125, cl. 6.8.1(b); Chapter 6, Part N, application note.
Source: NER version 255, cl. 6.8.1(b), cl. 6A.10.1A(b)

We are not required to amend or replace every decision or proposed approach in the last F&A.

2.2 Why legal effect matters

For DNSPs (but not TNSPs), some elements of the F&A will bind or constrain our discretion in determinations.

This guides our prioritisation of, and level of investment in, each element of the F&A prior to the determination process itself. Table 2 presents the three categories from greatest to least constraint.

Table 2 Legal effect of F&A matters

BINDS	CONSTRAINS	SETS EXPECTATIONS
Effect **The AER makes a final and binding decision at the F&A stage.**	Effect A departure test limits the AER's later discretion.	Effect Guides proposals and the reset but the AER may reconsider its approach.

[2] NER version 255, cl. 6.8.1(b), cl. 6A.10.1A(b)

BINDS	CONSTRAINS	SETS EXPECTATIONS
Dual function assets: distribution or transmission pricing framework.[3]	**Form of control mechanism** Must follow the F&A form unless the AER has departed from the relevant distribution service classification and determined that no listed control mechanism should apply.[4]	**Incentive schemes to apply in the upcoming period**
	Control formulae Must follow the formulae in the F&A unless a material change in circumstances justifies departure.[5]	**Application of the Expenditure Forecast Assessment Guidelines**
	Service classification Must follow the classification in the F&A unless a material change in circumstances justifies departure.[6]	**Use of forecast vs actual depreciation to roll forward the RAB**

2.3 What happens next

The primary purpose of this initial consultation is to establish the scope of our F&A review, not to settle final positions. We also invite early substantive views through the consultation questions throughout this paper. After considering submissions, we will decide which elements of the F&A to review. We will consult further on the substance of proposed amendments or replacements before publishing final F&As. The table below provides an indicative timetable.

Table 3 Indicative timeline for review of Framework and Approach papers

Phase	Timing	Indicative date	Milestone	What happens
Scoping	32 months before current period ends[7]	30 Oct 2026	NSPs submit requests for amendment or replacement of F&A	NSPs may request amendment or replacement of their F&A in respect of one or more matters. *All NSP-nominated matters are automatically in scope.*

3 NER version 255, cl. 6.25(d)

4 NER version 255, cl. 6.12.3(c); NER (NT) version 125, cl. 6.12.3(c).

5 NER version 255, cl. 6.12.3(c1); NER (NT) version 125, cl. 6.12.3(c1).

6 NER version 255, cl. 6.12.3(b); NER (NT) version 125, cl. 6.12.3(b).

7 NER version 255, cl. 6.8.1(c)(1), cl. 6A.10.1A(c)(1); NER (NT) version 125, cl. 6.8.1(c)(1).

Phase	Timing	Indicative date	Milestone	What happens
We are here 	**31 months before current period ends**[8]	**18 Nov 2026**	**AER invites submissions on any additional matters for amendment or replacement**	**The AER invites views on whether to amend or replace the F&A in respect of any additional matters.**
	30 months before current period ends[9]	30 Dec 2026	AER decision on scope of review	The AER states whether, and on what matters *in addition to those raised by the NSP*, it will consider making an amended or replacement F&A.
Positions	Scope-dependent	Mar–May 2027	Consultation	The AER consults NSPs and other stakeholders to test positions and invite challenge, especially on F&A elements that bind or constrain.
	23 months before current period ends[10]	30 Jul 2027	Final F&A	The AER publishes the final F&A.

8 NER version 255, cl. 6.8.1(c)(2), cl. 6A.10.1A(c)(2); NER (NT) version 125, cl. 6.8.1(c)(2).

9 NER version 255, cl. 6.8.1(c)(3), (d), cl. 6A.10.1A(c)(3), (d); NER (NT) version 125, cl. 6.8.1(c)(3), (d).

10 NER version 255, cl. 6.8.1(e), cl. 6A.10.1A(e); NER (NT) version 125, cl. 6.8.1(e).

3 Matters for amendment or replacement before the 2029–34 determinations

In the sections below, we discuss each element of the F&A and its purpose.

Of these, DNSPs have already asked us to consider amending or replacing the service classifications that were applied to their determinations for the current period. In addition to proposals made by DNSPs, we are open to submissions on what else our review of service classifications should encompass.

We are also seeking views on whether it is necessary or appropriate to review other elements of the F&A at the same time.

NSP requests also take the opportunity to seek clarification of—but not substantive changes to—the application of incentive schemes and the EFA Guidelines. While not formally part of this review, we will consider these requests and respond at the appropriate stage of the F&A and determination processes.

3.1 Dual function assets

Dual function assets are high-voltage transmission assets, generally operating from 66 kV to 220 kV, that form part of a distribution network. They operate in parallel with and support the high-voltage transmission network.[11]

Where a DNSP uses those assets to provide services that a TNSP typically provides, the NER deem services that would have been treated as prescribed transmission services as standard control services.[12]

The F&A that applies to a distribution determination must set out our decision as to whether transmission standard control services provided using a DNSP's dual function assets will be subject to transmission or distribution pricing rules.[13]

- Under distribution pricing rules, the DNSP would recover the costs of providing these services from all users of its network.
- Under transmission pricing rules, distributors may allocate dual function asset costs to both their own customers and a TNSP's broader customer base. (Any services provided using dual function assets that would, if provided by a TNSP, be negotiated transmission services (for example, negotiated connection services for large customers like data centres connecting directly to a dual function asset) will still be treated as negotiated services.)

11 NER version 255, cl. 6.24.2(a)

12 NER version 255, cl. 6.24.2(b)

13 NER version 255, cl. 6.8.1(b)(1)(ii)

The decision made in the F&A is binding for the purposes of the relevant distribution determination. We cannot revisit it later in the determination process.[14]

In making this decision we must consider whether the value of a DNSP's dual function assets used to provide transmission standard control services makes up such a material proportion of its Regulatory Asset Base (RAB) that different pricing treatment is warranted.[15] This is a point in time assessment, made for the 2029–34 period by reference to the composition of the DNSP's RAB on 1 July 2026.[16] Relevant considerations include:

- whether different pricing treatment would result in materially different prices for the DNSP's customers (including those connected directly to dual function assets and those connected to other distribution networks)[17]
- whether the materiality of the different prices is likely to impact future consumption, production and other investment decisions by actual or potential network users.[18]

We can also consider other relevant factors, such as cost reflectivity, or who benefits from the assets, and the relative administrative costs of different pricing costs (which consumers ultimately bear).[19]

To date, only Evoenergy and Ausgrid have dual-function assets that have been subject to transmission pricing rather than distribution pricing. As at 1 July 2026, dual function assets make up 16%[20] and 13.5%[21] of their respective RABs. These are similar outcomes to those reported at the time of the 2024-29 F&As.[22]

The coordinating TNSP for New South Wales and the ACT is Transgrid. Its network area includes the Ausgrid, Endeavour, Essential and Evoenergy distribution networks. Because Ausgrid and Evoenergy's dual function assets support Transgrid's network, providing services to Ausgrid and Evoenergy customers but also benefiting others, we have considered it appropriate that Ausgrid's and Evoenergy's own customers and the broader set of Transgrid's customers share dual function asset costs.

For other DNSPs, the portion of RABs made up of dual function assets remains considerably smaller and we have not, to date, considered introduction of separate revenue caps and pricing methodologies warranted.

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14 NER version 255, cl. 6.25(d)

15 NER version 255, cl. 6.25(b)

16 NER version 255, cl. 6.25(a)

17 NER version 255, cl. 6.25(c)(1)

18 NER version 255, cl. 6.25(c)(2)

19 NER version 255, cl. 6.25(c)(3)

20 Evoenergy - Request to amend or replace Evoenergy's framework and approach paper - October 2026, p. 5.

21 Ausgrid - Framework and Approach - Appendix C - Incentive schemes, depreciation and DFA - October 2026, p. 7.

22 As at 31 July 2021, dual function assets made up 18% of Evoenergy's RAB and 12% of Ausgrid's RAB.

Table 4 Percentage of RAB comprised of dual function assets (1 July 2026)

DNSP	% of RAB comprised of dual function assets
Endeavour Energy	5.4%
Essential Energy	2.37%
TasNetworks	0%

Source: Essential Energy - Framework and Approach for Essential Energy's 2029–34 regulatory control period - October 2026, p. 2; Endeavour Energy - Value of Endeavour Energy's dual function assets - October 2026

This part of the NER does not apply in the Northern Territory. We are therefore not required to make this decision for PWC.[23]

Consultation questions – dual function assets:

1) Does the application of transmission pricing rules to Ausgrid's and Evoenergy's dual function assets supporting Transgrid's transmission network remain appropriate? What reasons and evidence support your view?
2) Does the application of distribution pricing rules to Endeavour's, Essential's and TasNetworks' dual function assets supporting the Transgrid and TasNetworks transmission networks remain appropriate? What reasons and evidence support your view?

3.2 Form of control and supporting formulae

The F&A that applies to a distribution determination must set out our decision on the form (or forms) of the control mechanisms applicable to direct control services (standard and alternative control services), and our proposed approach to the formulae that will give effect to them.[24]

Control mechanisms define how DNSPs set prices and recover revenues.[25] In this paper we categorise the potential control mechanisms provided in the NER as either price or revenue-based. An overview is provided in Table 5. The NER provides the option for a combination of mechanisms to be applied in the form of different mechanisms applying to different groups of services, or a 'hybrid' mechanism that combines multiple mechanisms.[26] These 'hybrid' mechanisms generally adapt components of price and revenue-based mechanisms to better manage risks.

23 NER (NT) version 125, Chapter 6, Part N, application note: Part N currently has no effect in the Northern Territory.

24 NER version 255, cl. 6.8.1(b)(1)(i), (b)(2)(ii); NER (NT) version 125, cl. 6.8.1(b)(1)(i), (2)(ii).

25 NER version 255, cl. 6.2.5(a)–(b); NER (NT) version 125, cl. 6.2.5(a)–(b), 6.2.6.

26 NER version 255, cl. 6.2.5(b); NER (NT) version 125, cl. 6.2.5(b).

Table 5 Overview of control mechanisms

Price-based mechanisms involve the setting of prices, or price caps for each individual component of services, or weighted average price caps (WAPC) for groups of the components / services, for each year in the determination period using forecast quantities.[27]	
Fixed prices	DNSPs submit prices annually to match prices in determination.
Price caps	DNSPs submit prices annually at / or below price caps in determination.
Weighted average price cap (WAPC)	DNSPs submit prices annually that produce weighted average prices for the relevant groups of components, services, or tariffs at / below the WAPC in determination.
Revenue-based mechanisms establish revenue-related control for all services, or buckets of services, for each year in the determination period.	
Revenue caps	DNSPs submit prices annually that, when calculated with forecast quantities, do not exceed the revenue cap in the determination. This paper considers a revenue cap in line with other 'cap' mechanisms – an asymmetric mechanism where DNSPs cannot exceed, but may recover lower than, the allowed 'cap'.
Revenue yield control	Sets caps on the revenue to be recovered per a certain quantity (often kWh) for each year through the determination. DNSPs submit prices annually that, when calculated with forecast quantities, do not exceed the allowed revenue yield.
Fixed revenues	DNSPs submit prices annually that, when calculated with forecast quantities, match these fixed revenues. This 'hybrid' mechanism is currently applied for SCS.

While we currently apply fixed revenues for standard control services to all DNSPs, previously the WAPC applied in NSW, SA, and Victoria, and revenue yield control in ACT.[28] We prioritised revenue recovery certainty over price instability and efficient pricing incentives when we made these changes, starting in 2013. A price cap is applied to most alternative control services.

In WA and internationally, we see similarly regulated electricity distribution industries adopt revenue caps, fixed revenues, or variations of these mechanisms.

27 We use the term 'quantities' to refer to billable quantities, that, along with prices, determine revenue. These include customer numbers, consumption / usage, demand / capacity, and any billable component that has a price against it.

28 The previous ACT revenue yield control was referred to as an 'average revenue cap' mechanism. An 'average revenue cap' mechanism could also refer to a mechanism achieving an 'average revenue' across the applicable period.

We are seeking views on whether we should review the current forms of control and formulae as part of the F&A process for 2029–34.

These matters are important to settle at the F&A stage because they place strict constraints on the later distribution determination. **The form of control must remain as set out in the F&A unless we depart from the classification of a service and consider that none of the forms of control in the paper should then apply to that service.[29] The formulae must also remain as set out in the F&A unless the AER considers that a material change in circumstances justifies a departure.[30]** Including these matters in the review would therefore provide the main opportunity to consider changing them.

3.2.1 Current arrangements

The 6 DNSPs currently operate under a revenue cap form of control for standard control services. The currently applicable revenue cap operates as a hybrid mechanism, which can also be described as a 'fixed revenue' mechanism. This ensures DNSPs recover no more and no less than allowed. This contrasts to a traditional revenue cap, where DNSPs cannot recover more than allowed, but may recover less. A revenue cap gives a DNSP a high degree of certainty that it can recover the efficient revenue allowed in our determination. Each year, DNSPs set prices using current demand forecasts and correct differences between allowed and actual revenue in later years. This means consumers bear the price impacts when actual demand differs from forecast.

Alternative control distribution services are subject to various forms of price cap. Under most price caps, DNSPs set prices using demand (billable volume or quantity) forecasts from the determination and then adjust them over time by specified factors. Revenue is not automatically kept whole if actual demand differs from forecast. This means the DNSP generally bears the risk of under-recovering revenue where lower-than-forecast demand occurs, while consumers may bear the risk of paying more than they should if demand is higher than forecast.

3.2.2 Why consider including these matters in the review?

Demand is becoming harder to forecast, particularly for standard control services. Potential large customer connections, including data centres, may require substantial network investment but may not proceed as expected. Electrification of homes and transport, batteries, rooftop solar and other changes are also affecting when and how customers use networks. If forecasts are wrong, the consequences may be material for both DNSPs and consumers.

There are two related types of demand forecasting risk within the building block revenue calculation that forms part of a distribution determination:

- Expenditure-side risk arises when forecast demand affects the amount of operating or capital expenditure included in allowed revenue. If demand is over-forecast, consumers

[29] NER version 255, cl. 6.12.3(c)

[30] NER version 255, cl. 6.12.3(c1)

may pay for investment that is not needed or is needed later. If demand is under-forecast, a DNSP may need to spend more than allowed to meet demand.

- Price-side risk arises when actual billable demand differs from the forecast used to set prices under the control mechanism. Under a revenue cap, later true ups protect the DNSP's allowed revenue but can increase or reduce future prices. Under most price caps, the DNSP's revenue changes with actual demand and there is generally no later true-up. Also, under price caps, DNSPs must prepare forecasts earlier, leading to higher risk that actual demand will vary from forecasts.

No form of control removes all demand forecasting risk. The differences between revenue caps, price caps and hybrid approaches show that the form of control and its formulae may affect how price-side risk is shared, the incentives faced by DNSPs, tariff flexibility, price volatility and administrative cost. These potential effects, illustrated in Table 6, are reasons to consider whether the matters warrant review; particularly where demand is becoming more uncertain and harder to forecast. They do not indicate that the AER has formed a view that the current arrangements should change.

Table 6 Potential effects of price and revenue based control mechanisms

Criteria / risk	Price based	Revenue based
Revenue risk	DNSPs are exposed to revenue risk – upside and downside	DNSPs are not exposed to revenue risk under fixed revenues but are to downside risk under the revenue cap
Price risk	Consumers have price certainty / stability annually but may experience larger shifts across regulatory periods	Consumers are exposed to price uncertainty and volatility annually
Quantities / demand management	DNSPs incentivised to maximise use and minimise demand management (which may not be efficient)	DNSPs incentivised to minimise demand management (which may not be efficient) under revenue cap but may have some incentives to encourage demand management under fixed revenue
Administrative burden	Higher burden in determinations (quantity forecasts required) but lower during annual pricing	Lower burden in determinations but higher during annual pricing (quantity forecasts required)

3.2.3 What would an in-scope review consider?

If the AER includes form of control and formulae in the review, it will examine whether the current arrangements remain fit for purpose in a changing demand environment. This could involve assessing the operation of revenue caps, price caps and possible hybrid mechanisms, without presuming that the AER should adopt any option.

The review would consider the need for efficient tariff structures, administrative cost, and consistency across networks, as well as other relevant factors including who is best placed to manage different risks, likely effects on prices and revenue recovery, incentives for efficient forecasting and demand side management, transparency and tariff flexibility.[31] It could also test how the current arrangements perform in different scenarios—for example, where a major connection proceeds later than forecast, does not proceed, or grows faster than expected.

3.2.4 Relationship with other regulatory mechanisms

The form of control mainly influences how price-side demand risk is shared. It does not by itself manage price risk, nor does it correct expenditure approved on the basis of an inaccurate demand forecast. The AER must therefore consider the form of control alongside the quality of demand forecasts, expenditure assessment and other mechanisms in the regulatory framework.

These supporting mechanisms may include contingent projects[32] for investment whose timing or need remains uncertain; cost pass-throughs[33] or capital expenditure reopeners for eligible unforeseen events[34]; incentive schemes and later adjustments based on actual expenditure; tariff structure statements and side constraints[35]; and targeted true-ups, caps, collars or other adjustments to limit large revenue or price movements. Each of these mechanisms has trade-offs, including possible delays, complexity, weakened incentives or price changes in later periods.

Including form of control and formulae in the review would allow the AER to assess their role alongside these other mechanisms. It would not assume that changing the form of control or formulae is necessary, or that these matters alone can address demand uncertainty.

Consultation question – form of control and supporting formulae

3) Is the existing form of control still the mechanism that best promotes the National Electricity Objective given the fundamental changes occurring in the electricity system?

4) What aspects, if any, of the current forms of control for standard control and alternative control services, and their supporting formulae, warrant review in the 2029–34 F&A process for the six DNSPs?

What reasons and evidence support your views?

31 NER version 255, cl. 6.2.5(c); NER (NT) version 125, cl. 6.2.5(c).

32 NER version 255, cl. 6.6A.1–6.6A.2; NER (NT) version 125, cl. 6.6A.1–6.6A.2.

33 NER version 255, cl. 6.6.1; NER (NT) version 125, cl. 6.6.1.

34 NER version 255, cl. 6.6.5; NER (NT) version 125, cl. 6.6.5.

35 NER version 255, cl. 6.18.1A, 6.18.6; NER (NT) version 125, cl. 6.18.1A, 6.18.6.

3.3 Service classification

The F&A for a DNSP must set out our proposed classification of distribution services for the 2029–34 period.[36] **The classification adopted in the distribution determination must remain as set out in the relevant F&A unless we consider that a material change in circumstances justifies a departure**.[37]

Service classification decides which distribution services we economically regulate through a distribution determination, who pays for them and how we control their prices and terms. It therefore affects basic network charges, service-specific charges, negotiated arrangements and the regulatory protections available to consumers and service applicants.

3.3.1 How we classify services covered by distribution determinations

We approach service classification in three stages. At each stage, the NER direct attention to practical questions about whether economic regulation is needed, how widely the service and its benefits extend, whether its costs can be attributed to particular customers, and whether competition or informed negotiation can provide an effective alternative to prescribed regulation.

1. Is the activity a distribution service?

   Before we can classify a service, it must be a service provided by means of, or in connection with, a distribution system.[38] We must answer this threshold, interpretive question before classifying a service; it is not a decision we are required to make in an F&A or determination in its own right. It identifies whether the service in question *can* be brought within the distribution determination.

2. Should the distribution service be directly controlled or negotiated?

   If we decide that a distribution determination *should* cover a distribution service, the first decision we must make is whether it should be a direct control service or a negotiated distribution service.[39]

   A direct control service is subject to regulated prices or revenues through the distribution determination.[40] This treatment may be appropriate where a DNSP has enduring market power, barriers to entry are material, substitutes are limited or users lack the information or bargaining power needed to protect their interests in negotiation with a DNSP. A negotiated distribution service remains regulated, but its prices and terms are settled under an approved negotiating framework and negotiated distribution service criteria rather than being preset.[41] This may be appropriate where service applicants can negotiate with the DNSP on an informed basis and have sufficient countervailing bargaining power.

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36 NER version 255, cl. 6.8.1(b)(2)(i); NER (NT) version 125, cl. 6.8.1(b)(2)(i)

37 NER version 255, cl. 6.12.3(b); NER (NT) version 125, cl. 6.12.3(b).

38 NER version 255, cl. 6.1.1(a), 6.2.1(a); Chapter 10 – Glossary; NER (NT) version 125 cl. 6.1.1(a), 6.2.1(a); Chapter 10 – Glossary

39 NER version 255, cl. 6.2.1(a); NER (NT) version 125, cl. 6.2.1(a)

40 NER version 255, cl. 6.2.5(a); NER (NT) version 125, cl. 6.2.5(a)

41 NER version 255, cl. 6.7.2(a); NER (NT) version 125, cl. 6.7.2(a)

In making this choice, we consider the form of regulation factors in the National Electricity Law (NEL).[42] These factors require us to examine the market in which the service is provided, including barriers to entry, links with other network and non-network services, the availability of substitutes, the responsiveness of demand, users' bargaining power and whether they have enough information to negotiate effectively. These considerations explain why direct control may be needed where services are provided on a monopoly basis or in a market where substitute services are limited, while negotiated treatment may be suitable where informed negotiation can provide an effective discipline. We must also consider the form of regulation previously applied to the service, the treatment of similar services and any other relevant matter.[43]

3. If the service is directly controlled, should it be standard control or alternative control?

   Standard control services are generally natural monopoly services used by, or benefiting, most customers. DNSPs recover their efficient costs through regulated network charges shared across the relevant customer base. Alternative control services are also subject to regulated prices or revenues but are generally used by identifiable customers or provided in markets with some scope for competition. DNSPs usually recover their efficient costs directly from users through regulated service-specific charges.

   The NER requirements for this third stage align with these practical distinctions. We consider the potential for competition and how classification as standard or alternative control may affect it, the administrative costs of regulation, the treatment previously applied to the service, consistency with similar services, whether the DNSP can attribute costs directly to the person receiving the service and any other relevant factor.[44] Broad network benefits and costs that cannot readily be attributed to individual users may support standard control treatment and shared cost recovery. By contrast, alternative control treatment may be more appropriate where the service and its costs can be linked to identifiable users, shared recovery is not justified, or a targeted price control can preserve scope for competition.

Previous classifications and consistent treatment of similar services within and across determinations support predictable outcomes, but they are not determinative. A different classification may be justified where market conditions, technology, service models, jurisdictional obligations or consumer impacts have changed. Where the NER prescribes a particular classification, however, we must apply it.[45] For example, a distribution service provided through a regulated stand-alone power system (SAPS) must receive the classification it would have received on the interconnected distribution system. We must treat other qualifying distribution services, and the inputs used to establish and maintain the stand-alone system, as standard control services, except where the specific exclusion for electricity production applies.[46]

Taken together, the classification options balance regulation and competition in the long-term interests of consumers. Stronger, shared regulation may be justified where natural monopoly characteristics and broad network benefits require it. More targeted direct control or

42 NEL, s. 2F.

43 NER version 255, cl. 6.2.1(c); NER (NT) version 125, cl. 6.2.1(c).

44 NER version 255, cl. 6.2.2(c); NER (NT) version 125, cl. 6.2.2(c).

45 NER version 255, cl. 6.2.1(e), 6.2.2(e); NER (NT) version 125, cl. 6.2.1(e), 6.2.2(e).

46 NER version 255, cl. 6.2.1A(b)–(d); NER (NT) version 125, cl. 6.2.1A(b)–(d).

negotiated treatment may be appropriate where costs are attributable to particular users, credible substitutes exist or regulation could unnecessarily impede competition.

3.3.2 Matters DNSPs have raised for the 2029–34 review

All six DNSPs have asked us to review the service classifications that have applied in the 2024-29 period (Appendix A provides links to these classification decisions) as new services, technologies and delivery models emerge. We have yet to assess the changes proposed, which include the following:

- **Electric vehicle charging infrastructure**—Ausgrid, Endeavour, Essential and PWC propose providing access to distributor-owned EV charging infrastructure as a new standard control service, with competitive businesses then providing customer-facing charging services. Ausgrid, Essential and PWC focus their proposals on underserved, or rural and regional locations where they consider market-led investment may not deliver the required infrastructure.[47]
- **Distribution asset rental services for EVCI**—TasNetworks proposes a negotiated distribution service for rental of its poles and other distribution assets to third parties that would install and operate their own chargers. This would be consistent with the service classified in our recent, 2026–31 determinations for Victorian DNSPs.[48]
- **Leasing spare network battery capacity**—Ausgrid, Essential, TasNetworks and Endeavour propose making spare capacity in network batteries available to third parties for contestable activities once network requirements have been met. Ausgrid proposes we classify leasing capacity in batteries below 5 MW as a standard control service, with only the network-benefit share of costs included in the regulatory asset base. Essential, TasNetworks and Endeavour propose to make spare capacity available but ask us not to classify that service. Endeavour proposes, however, that we classify the legal and administrative work to facilitate leases as a standard control service.[49]
- **Local energy precincts**—Ausgrid's Community Power Network pilot, which coordinates local generation, storage and demand, operates at Charmhaven and Mascot-Botany under a time-limited trial waiver granted by the AER in December 2025 through its regulatory sandbox.[50]

  Its proposed Local Energy Precincts service would build on that pilot under a new standard control service. The proposed activities include prioritising network needs

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47 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 9–13; Endeavour Energy - Request to amend the Framework and Approach Paper - October 2026, pp. 4–6; Essential Energy - Framework and Approach for Essential Energy's 2029–34 regulatory control period - October 2026, p. 4; Power and Water Corporation - Request for a replacement Framework and Approach paper – 2029–34 regulatory period - Attachment - October 2026, pp. 8–9.

48 TasNetworks - Attachment 1 - Proposed Framework and Approach Variations - October 2026, pp. 12–13.

49 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 5–6; Essential Energy - Framework and Approach for Essential Energy's 2029–34 regulatory control period - October 2026, p. 5; TasNetworks - Attachment 1 - Proposed Framework and Approach Variations - October 2026, p. 13Endeavour Energy - Request to amend the Framework and Approach Paper - October 2026, pp. 7–8.

50 AER, Trial waiver decision – Ausgrid Community Power Network, December 2025; Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 14–15; Ausgrid - Framework and Approach - Appendix D - Community Power Networks - October 2026, p. 3.

through battery operating limits, releasing spare capacity, buying local commercial and industrial solar output and enabling its wholesale trade, and paying a customer dividend. Ausgrid requests classification for both the completion of the Charmhaven and Mascot-Botany pilot and a business-as-usual phase, conditional on AER confirmation of agreed success conditions. It also proposes related revenue-adjustment and benefit-sharing arrangements for approved expansion.[51]

- **Distribution System Operation**—Ausgrid, Evoenergy and Power and Water propose that we classify distribution system operator (DSO) functions that monitor network conditions, manage capacity and coordinate consumer energy resources and flexible loads as a standard control service. Services contemplated include visibility, forecasting, adaptive planning, operating envelopes, standardised data and interfaces, dynamic capacity management, flexible exports and resource integration and orchestration. Endeavour Energy separately seeks express recognition of dynamic network capacity management, including communication of import and export limits, as a standard control service.[52]
- **System services**—Evoenergy proposes that we classify mandatory essential system activities undertaken at AEMO's direction, including emergency backstop curtailment of embedded generation, under-frequency load management and associated compliance and testing, as standard control services. Ausgrid proposes that we classify its delivery of contestable AEMO-requested support, such as reserves, restart, frequency control and inertia, and contracted system strength services to Transgrid using suitable distribution assets, as standard control services, but exclude associated revenue recovery from that classification.[53]
- **Data centre connection services**—Ausgrid and Power and Water seek customer-specific treatment of data centre connections but propose different service scopes and classifications. Ausgrid requests negotiated distribution service treatment for identified-user shared connection assets, while dedicated, electrically separable assets would remain unclassified, and use of the wider shared network would remain standard control. Power and Water proposes a new Data Centre Connections service classified as an alternative control service, covering assessment, design and delivery of bespoke connection assets and augmentations, capacity reservation, connection management and operational support.[54]

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51 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 14–18; Ausgrid - Framework and Approach - Appendix D - Community Power Networks - October 2026, pp. 3, 5–9.

52 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 19–21; Evoenergy - Request to amend or replace Evoenergy's framework and approach paper - October 2026, pp. 5, 12; Power and Water Corporation - Request for a replacement Framework and Approach paper – 2029–34 regulatory period - Attachment - October 2026, pp. 9–11; Endeavour Energy - Request to amend the Framework and Approach Paper - October 2026, p. 7.

53 Evoenergy - Request to amend or replace Evoenergy's framework and approach paper - October 2026, pp. 5, 13; Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 20–21, 50–51.

54 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 26–28; Power and Water Corporation - Request for a replacement Framework and Approach paper – 2029–34 regulatory period - Attachment - October 2026, pp. 11–12.

- **Metering services**—Ausgrid, Evoenergy and TasNetworks seek reclassification of routine Type 5 and 6 legacy metering services from ACS to SCS. These services support the remaining Type 5 and 6 meters on their networks through reading, relevant inspections or testing and metering data processing. Ausgrid and Evoenergy propose retaining the current alternative control classification for customer-initiated special services.[55]
- **Public lighting services**—Essential and Endeavour propose the inclusion of Type 9 metering (using measurement capability integrated into smart lighting equipment) within their existing, alternative control service public lighting group.[56]

  Power and Water separately proposes a new, alternative control service grouping for public lighting maintained and repaired for Alice Springs Town Council, with PWC recovering the associated costs from that customer. These are services that PWC already provides, but which our distribution determination has not previously covered.[57]
- **Specialist calibration services**—Ausgrid proposes that we classify specialist standards-level calibration of external secondary laboratories' reference instruments as an alternative control service, excluding general equipment calibration and calibration of its own equipment.[58]
- **Network materials testing and verification services**—Essential Energy proposes expanding its existing 'Authorisation and approval of third-party service providers' design, work and materials service' to include fee-based testing and verification of materials and components for use on Essential Energy's network for external parties.[59]
- **Integration, monitoring and switching services provided to customers**—Endeavour Energy proposes that we classify customer-requested control-system integration, remote monitoring and switching as a new alternative control service. The service would integrate customer-operated systems with its distribution management system.[60]
- **Registration of Private Underground Services on Public Land**—TasNetworks currently enters information about privately owned underground electricity cables located on public land into the Before You Dig Australia (BYDA) database under a ring-fencing waiver granted by the AER. Going forward, it proposes that we classify registration of privately owned underground electricity services on public land with Before You Dig Australia as an alternative control service.[61]

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55 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 31–33, 47; Evoenergy - Request to amend or replace Evoenergy's framework and approach paper - October 2026, pp. 6, 18; TasNetworks - Attachment 1 - Proposed Framework and Approach Variations - October 2026, p. 7.

56 Essential Energy - Framework and Approach for Essential Energy's 2029–34 regulatory control period - October 2026, pp. 5–6; Endeavour Energy - Request to amend the Framework and Approach Paper - October 2026, p. 7.

57 Power and Water Corporation - Request for a replacement Framework and Approach paper – 2029–34 regulatory period - Attachment - October 2026, pp. 7–8.

58 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 34–35.

59 Essential Energy - Framework and Approach for Essential Energy's 2029–34 regulatory control period - October 2026, p. 6.

60 Endeavour Energy - Request to amend the Framework and Approach Paper - October 2026, p. 6.

61 TasNetworks - Attachment 1 - Proposed Framework and Approach Variations - October 2026, pp. 11–12.

Ausgrid, Endeavour Energy and Evoenergy have also requested changes they consider would clarify descriptions of a number of existing services, including network data services, enhanced connection services, customer safety information, internal training for staff and contractors undertaking direct control services, investigation of customer-reported network faults, and limited simple customer-fault rectification, subject to the limits in its proposed description.[62]

Consultation questions – service classification

5) Which services identified by DNSPs, if any, should we regulate through our distribution determinations in 2029–34? For each service, what reasons and evidence support your view on whether we should regulate it and, if so, its classification as a standard control, alternative control or negotiated distribution service?

6) What additional distribution services, if any, should we consider (or reconsider) in our review of service classifications for 2029–34? For each service, what reasons and evidence support its inclusion in the review and your view on whether, and if so under what classification we should regulate it?

Kerbside EV charging rule change proposals and implications for classification

On 24 September 2026, the AEMC published a draft determination on the Commonwealth Government Department of Climate Change, Energy, the Environment and Water's (DCCEEW) proposed rule change to facilitate the Accelerating EV Charging Program.[63] The program would support a targeted, time-limited rollout of kerbside charging in metropolitan areas and DC charging in regional blackspots. Participating DNSPs would undertake approved activities, with electricity consumers funding part of the efficient costs.

Neither the proposal nor the draft determination recognises the approved activities as conventional customer services that DNSPs would offer or sell to customers. Instead, a narrow transitional rule would treat activities such as site identification, connection works, charger installation and maintenance as standard control services for ring-fencing and cost recovery under the DCCEEW program. This would allow participating DNSPs to undertake approved activities and recover eligible costs across their customer base. The AEMC considered the form of regulation factors, the National Electricity Objective, the revenue and pricing principles, and the available service classifications. It found that user-pays classifications would not be workable for deliberately uneconomic program sites. The proposed treatment is limited to approved activities, sites and funding, and to the economic life of program assets. It would not classify EV charging generally or determine the enduring role of DNSPs in EV charging markets.

The draft rule would not displace or predetermine service classification decisions in this F&A process or the subsequent distribution determinations. A DNSP could still propose the same or similar activities outside the program, but we would assess them on their own facts under

62 Ausgrid - Framework and Approach - Appendix A - Service classification - October 2026, pp. 19–21; Endeavour Energy - Request to amend the Framework and Approach Paper - October 2026, p. 7; Evoenergy - Request to amend or replace Evoenergy's framework and approach paper - October 2026, pp. 7–8, 12, 14, 16–17, 19–21.

63 Facilitating EV charging infrastructure rollout under Commonwealth grants | AEMC

the ordinary Chapter 6 framework, including market conditions, consumer benefits and costs, and competitive or user-pays alternatives. We could therefore reach a different classification.

At the time we published this consultation paper, a final determination on this rule change was expected by December 2026.

Broader questions about enduring DNSP-led EVCI, competition safeguards and ring-fencing remain under the ENA and Nexa Advisory rule changes and Package 1 of the Electricity Network Regulation Review[64], key policy positions for which are expected by March 2027:

- ENA's Enabling DNSP-led electric vehicle charging infrastructure rule change proposal[65] seeks an enduring framework for DNSPs to provide kerbside EVCI as a regulated service, rather than the temporary treatment of specified activities under the DCCEEW program.
- Nexa Advisory's Clarifying distribution ring-fencing in emerging energy markets rule change proposal[66] seeks stronger safeguards against cross-subsidisation, discrimination and unfair advantages where DNSPs participate in emerging competitive markets.

3.3.3 Accommodating new services during the period

New services may emerge after we make the 2029–34 determination, when changing an approved classification or control can be difficult.[67]

For simplicity and where appropriate, we have classified services in groupings rather than individually.[68] Referring to a grouping allows us to collect groups of services with common attributes that are often (but not always) classified similarly. An existing grouping may cover a new service that emerges after we make a determination only where its nature is clearly consistent with that grouping. Otherwise, it will generally remain unclassified until we consider it in a later determination. Groupings therefore need to provide useful flexibility without obscuring the regulatory boundary.

- **Standard control services:** a broad grouping may capture a genuinely similar new service, but the approved revenue or price control will not necessarily provide additional funding.
- **Alternative control services:** a sufficiently clear grouping and quoted-price approach may allow a DNSP to price a similar new service by reference to comparable services.
- **Negotiated distribution services:** a service-neutral framework may accommodate a new service where informed negotiation and commensurate bargaining power are realistic.

We are seeking views on how we can draft service groupings around the nature of the service—rather than a particular technology, asset, input or cost-recovery method—while

64 Electricity Network Regulation Review – Package 1 | AEMC

65 Enabling distribution network service provider led electric vehicle charging infrastructure | AEMC

66 Clarifying distribution ring fencing in emerging energy markets | AEMC

67 NER version 255, cl. 6.2.3.

68 NER version 255, cl. 6.2.1(b), 6.2.2(b); NER (NT) version 125, cl. 6.2.1(b), 6.2.2(b), 6.2.3.

remaining clear enough for consumers, service applicants and DNSPs to understand the applicable pricing and protections.

Consultation questions – service classification (cont.)

7) What changes, if any, to the service groupings we use for classification purposes would help accommodate genuinely similar new services emerging during 2029–34, while maintaining clarity about regulatory coverage, pricing, cost recovery and consumer protections? What reasons and evidence support your view?

3.4 Incentive schemes

Our determinations encourage NSPs to seek efficiencies and manage cost pressures without sacrificing performance. Our regulatory approach uses a benchmark incentive framework to set maximum revenues. Once we set revenues for a 5-year period, a network that keeps its actual costs below forecast retains part of the benefit. This encourages service providers to become more efficient over time. We reinforce these incentives with targeted schemes that apply from the start of each regulatory period.

Our F&A for both DNSPs and TNSPs sets out our proposed approach to the application of incentive schemes in the upcoming period.[69]

3.4.1 Current arrangements

The current incentive schemes are:

- The Efficiency Benefit Sharing Scheme (EBSS)[70] and Capital Expenditure Sharing Scheme (CESS)[71] encourage efficiency in NSPs' actual operating expenditure (opex) and capital expenditure (capex). They reward efficiency gains and penalise efficiency losses, measured against the difference between forecast and actual expenditure.[72]
- The Service Target Performance Incentive Scheme (STPIS)[73] provides financial incentives to maintain and improve reliability and (for DNSPs) customer service performance, so that NSPs do not reduce costs imprudently or inefficiently at the expense of service quality.[74]

69 NER version 255, cl. 6.8.1(b)(2)(iii)–(vii), cl. 6A.10.1A(b)(1)–(4), (7); NER (NT) version 125, cl. 6.8.1(b)(2)(iii)–(vii).

70 AER efficiency benefit sharing scheme - November 2013 | Australian Energy Regulator (AER)

71 AER Capital Expenditure Incentive Guidelines - August 2025 | Australian Energy Regulator (AER)

72 NER version 255, cl. 6.5.8(a), (c), 6.5.8A(a), (c)–(e), cl. 6A.6.5(a)–(b), 6A.6.5A(a), (c)–(e); NER (NT) version 125, cl. 6.5.8(a), (c), 6.5.8A(a), (c)–(e).

73 AER - Service Target Performance Incentive Scheme v 2.0 - updated 13 December 2018 | Australian Energy Regulator (AER); AER - Electricity Transmission Service Target Performance Incentive Scheme Version 6 - April 2025 | Australian Energy Regulator (AER);

74 NER version 255, cl. 6.6.2(a), (b)(3), NER version 255, cl. 6A.7.4(a)–(b); NER (NT) version 125, cl. 6.6.2(a)–(b).

- A DNSP can propose a Customer Service Incentive Scheme (CSIS)[75] as an alternative to the default customer service performance measures in the STPIS, giving priority to improvements in areas identified to be of greater concern to its consumers.
- The Demand Management Innovation Allowance Mechanism (DMIAM)[76] applies to both DNSPs and TNSPs.[77] DNSPs may also receive incentives under the Demand Management Incentive Scheme (DMIS).[78] These schemes encourage demand management and non-network solutions where they are efficient alternatives to traditional network investment.

Table 7 Application of incentive schemes in 2024-29 determinations

Scheme	Ausgrid	Endeavour	Essential	Evoenergy	PWC	TasNetworks DNSP / TNSP
EBSS	Applied	Applied	Applied	Applied	Applied	Applied / Applied
CESS	Applied	Applied	Applied	Applied	Applied	Applied / Applied
STPIS	Applied	Applied	Applied	Applied	Not applied	Applied / Applied
CSIS	Applied	Applied	Applied	Not applied	Not applied	Applied / N/A
DMIAM	Applied	Applied	Applied	Applied	Applied	Applied / Applied
DMIS	Applied	Applied	Applied	Applied	Applied	Applied / N/A

Evoenergy did not proceed with its proposed CSIS for 2024-29, because insufficient historical data were available to set appropriate targets for the proposed parameters.

We decided not to apply the STPIS to PWC because its systems and data collection were not sufficiently mature to support accurate reporting against most service-performance measures. PWC did not propose a CSIS for 2024–29 while it focused on implementing the existing incentive schemes during the early stages of economic regulation under the NER.

3.4.2 Developments relevant to 2029-34

While the suite of available incentive schemes is the same for 2029–34 as it was for 2024–29, a number of developments have arisen since our last determinations that will be relevant to how those incentive schemes apply in 2029–34.

75 AER - Final Customer Service Incentive Scheme - July 2020 | Australian Energy Regulator (AER)

76 AER - Demand management innovation allowance mechanism (version 1.01) - 16 January 2026 | Australian Energy Regulator (AER); AER - Demand management innovation allowance mechanism (version 1.01) - Transmission - January 2026 | Australian Energy Regulator (AER)

77 NER version 255, cl. 6.6.3A(a)-(c), cl. 6A.7.6(a)–(c); NER (NT) version 125, cl. 6.6.3A(b)–(c).

78 AER - Demand management incentive scheme - 14 December 2017 | Australian Energy Regulator (AER); NER version 255, cl. 6.6.3(a)-(c); NER (NT) version 125, cl. 6.6.3(a)-(c)

3.4.2.1 DMIS, DMIAM and alternative innovation funding

Promoting innovation is important to achieving an efficient energy transition. The Demand Management Innovation Allowance Mechanism (DMIAM)[79] and Demand Management Incentive Scheme (DMIS)[80] were intended to spur NSP innovation, with a focus on demand management and non-network solutions.

We do not apply the DMIAM in all determinations.[81] Our decision for Queensland TNSP Powerlink's current (2022–27) period accepted, with consumer support, its proposals that a DMIAM not apply. Our draft decision for its upcoming 2027–32 period has accepted this again.

Where these schemes have applied, however, uptake has been limited. The reasons for this are unclear. It could relate to the strength of the financial incentive, to the eligibility criteria, to NSP cultural issues or simply to a preference to pursue financing for innovative projects through the business-as-usual revenue determination process instead. For example, we have established ex ante innovation allowances (both capex and opex) in recent revenue determinations.

As we noted in our recent submission to the AEMC's ENRR Package 2[82], our August 2025 letter to the Treasurer[83] suggested we might take this further and consult publicly on a standard innovation allowance (as percentage of Maximum Allowed Revenue) for all electricity NSPs without requiring NSPs to submit an ex ante proposal or the AER to assess one, and operating under a 'use it or lose it' funding arrangement.

Consultation questions:

8) What aspects, if any, of the application of the DMIS to the six DNSPs and the DMIAM to those DNSPs and TasNetworks as a TNSP could be reviewed in the 2029–34 F&A process in order to provide more effective incentives? What reasons and evidence support your view?

3.4.2.2 New adjustments under the CESS

The current CESS is version 4, set out in the 2025 *Capital expenditure incentive guidelines*. Since the previous determinations for these NSPs, we have amended it to add new ex-post and ex-ante adjustments to the CESS. For the purposes of the 2029-34 F&As, this is the most recent version of the CESS and the one that will apply in the 2029–34 period.

Within the boundaries of a revenue determination, NSPs can generally choose how to deliver their capex programs and prioritise (or reprioritise) projects during a regulatory control period. However, they have limited control over the number and timing of connection requests customers submit. Because NSPs must respond to these requests, differences between

79 NER version 255, cl. 6.6.3A(b), cl. 6A.7.6(b)

80 NER version 255, cl. 6.6.3(b);

81 NER version 255, cl. 6A.10.1A(b)(7), 6A.14.1(5A)

82 AER submission - AEMC Electricity Network Regulation Review package 2 consultation paper | Australian Energy Regulator (AER)

83 Letter to the Treasurer - Regulatory reform opportunities - August 2025 | Australian Energy Regulator (AER)

forecast and actual connections capex within a control period may reflect errors in the forecast number of connections rather than efficiency in connection costs.

- For business-as-usual connections, version 4 of the CESS applies a symmetrical volumetric adjustment for DNSPs. The ex-ante adjustment accounts for changes in connection volumes. This reduces windfall rewards or penalties where actual connection demand differs from forecast.
- Large bespoke connections require a different approach because standard unit rates cannot reliably represent their costs and characteristics. An example may be a data centre connection and related augmentation costs, which will vary depending on the customer's requirements. If a DNSP undertakes a large bespoke connection in a control period that its approved forecast did not include, version 4 of the CESS allows us to reduce any resulting penalty after an ex post review.

For TNSPs, we may make a similar adjustment in respect of efficient capex on projects not included in approved forecast capex, again after an ex post review .[84] This takes into account the risk that the standard application of the CESS may not recognise prudent and efficient changes to the overall volume of work a TNSP undertaken during a regulatory period.

Together, these mechanisms protect NSPs and consumers from windfall gains or losses caused by connection forecasting errors. They also preserve incentives for efficient delivery of new connections.

Version 4 of the CESS does not allow any further exclusions: subject to the three prescribed instances above, the entirety of NSPs' capex is subject to the scheme.

We decide the CESS that applies to a regulatory control period when we make the determination, using the forecast information available at that time.[85] When we calculate CESS outcomes at the conclusion of a control period, NSPs may voluntarily reduce or forego a CESS reward, or increase a CESS penalty, if this directly benefits consumers by lowering their recoverable revenue. NSPs cannot, however, propose to increase the revenue recoverable from customers by reducing a CESS penalty accrued under the scheme, or by increasing a CESS reward.

For the current 2024–29 period, the CESS in the 2023 *Capital expenditure incentive guidelines* (version 2) continues to govern rewards and penalties accrued during that period. We did not, and now cannot, apply any exclusions to capex for that period.

Exclusions from the opex EBSS

Unlike the CESS, the EBSS does not prescribe specific exclusions. Instead, we determine which opex categories are subject to the EBSS based on the best forecasting methodology for that category of costs. In practice, this means that we decide exclusions at the same time as we make our decision on total forecast opex, not before the opex forecast is considered.

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84 AER, *Capital Expenditure Incentive Guidelines Review 2025 – Explanatory Statement for Final Guidelines*, August 2025

85 NER version 255, cl. 6.5.8A(e), 6.12.1(i), cl. 6A.6.5A(e), 6A.14.1(5A)

We forecast most of an NSP's opex using a revealed cost base-step-trend methodology. We take actual opex in a recent year and, after ensuring it provides an efficient baseline, trend it forward over the next period to account for the expected rate of change in input prices, output and productivity. Where necessary, we then add or subtract 'step changes' for increases or decreases in costs that the base year and rate of change do not account for (e.g., costs associated with a new regulatory obligation imposed after the base year, or capex/opex substitutions made since the base year that would mean it is no longer reflective of future costs). We effectively grant those step changes for future periods as well: they form part of the base year used for future periods.

We designed the EBSS to share efficiency gains and losses between the service provider and consumers.[86] When we forecast opex using the revealed cost methodology, an efficiency gain can generate an EBSS reward for the service provider and also reduce the opex forecast—and therefore the amount consumers pay—in the next period. The entirety of the revealed cost forecast is therefore subject to the EBSS.

Where the revealed cost methodology is not the best forecasting methodology for a category of costs, we add them to the total revealed cost forecast as a category specific forecast. At the following determination, if we remain satisfied these costs should not be forecast on a revealed cost basis, we do not include the costs incurred in the base year as part of the base used to forecast total opex. They are forecast separately. As such, any efficiency gains (or losses) made are not passed on to network users through a lower (or higher) total opex forecast. For example, costs for non-network options (network support costs), are typically excluded from the EBSS for TNSPs because they have traditionally been forecast on a bottom up basis (if at all). We do this for TNSPs (but not DNSPs) because for TNSPs those costs are subject to ex post true up through the prescribed network support pass through mechanism in chapter 6A. To apply this mechanism, we need a forecast of network support costs.

The sharing of efficiency gains and losses under the EBSS would not work in the same way where we use a category-specific forecast. In those circumstances, an efficiency gain may not flow through to a lower forecast for consumers. Applying the EBSS could therefore require consumers to fund a reward without receiving the corresponding benefit. For this reason, we typically exclude category specific opex forecasts from the EBSS. In this context it is worth noting that the EBSS is not the only way that efficiency gains and losses are shared. While an NSP would not receive any EBSS rewards for underspending on a category specific forecast they would—if those costs were excluded from the EBSS— retain 100% of any unspent forecast costs. This is more than the approximate share of 30% the NSP would receive if the costs were subject to the EBSS and the revealed costs are used to forecast opex.

3.4.2.3 CSIS and STPIS customer service incentives

Consumers and DNSPs can collaborate on customer service performance parameters and targets that could apply under a CSIS, instead of the customer service parameters under the

[86] NER version 255, cl. 6.5.8(a), cl. 6A.6.5(a)

STPIS.[87] Like the STPIS, a CSIS may financially reward or penalise DNSPs based on performance against their customer service targets. We consult on the STPIS and then set it out in AER guidelines for application to all DNSPs. By contrast, each DNSP designs its own CSIS in consultation with its consumers. Where a DNSP has consumer support to propose a CSIS, it must work with them to co-design and propose a scheme in line with those principles for each determination.

At the time we must publish the 2029-34 F&As, DNSPs may not have finished this design process. We cannot, therefore, propose an approach to the application of a CSIS that would guarantee its success. What we can say, and have said in previous F&As, is that we are open to the application of a CSIS where a DNSP includes it in its January 2028 proposal, provided that proposal meets all applicable requirements.

As we approach the 2029-34 determinations and DNSPs engage with consumers on whether to include a CSIS in their proposals, the following context warrants attention.

Since its introduction, the CSIS has faced significant compliance issues, including suspensions and transitional concessions. In recent years, the quality of proposals has also declined, with proposals lacking sufficient scope, customer support or completeness to demonstrate compliance with the scheme's requirements. Consumer representatives, DNSPs and customers have raised concerns about duplication with the STPIS and jurisdictional incentives. Some have suggested replacing the CSIS with performance reporting that has no financial incentive.

To deliver its intended benefits, a CSIS must have a robust design, clear objectives and measurable performance parameters. We expect each proposal to address 4 areas:

1. **Performance parameters** must relate to the customer experience of standard control services and address outcomes customers genuinely value and want improved. Proposals should show broad, repeated engagement across customer groups—including vulnerable households, small businesses and commercial and industrial customers—and clear customer support for the priorities selected. Outcomes must be substantially within the DNSP's control and must not duplicate outcomes that another scheme or jurisdictional arrangement already incentivises. Financial incentives such as those under a CSIS are appropriate where NSP behaviour can materially affect an observable outcome, rather than where an existing regulatory obligation is sufficient to establish the required standard. This keeps the CSIS focused, avoids duplicate or excessive incentives, and ensures the CSIS rewards or penalises DNSPs only for outcomes they can materially influence.

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87 The STPIS includes four potential customer service parameters for DNSPs:

- Telephone answering—calls to a fault line answered by a human operator in 30 seconds (including time while a call is ringing but unanswered or held in a queue, but excluding time connected to an automated interactive service that provides substantive information).
- Streetlight repair—the percentage of public lights repaired within a defined number of business days from a fault.
- New connections—the percentage of total new connections completed on or before the date agreed with the customer.
- Response to written enquiries—the percentage of written responses provided to written enquiries (including emails) on or before a defined threshold.

2. **Measurement methodologies** for each parameter must be targeted, objectively verifiable and clearly reflect the intended customer outcome. They should not rely on proxies or extrapolation. The method must also be sufficiently independent, either through third-party administration or an independently developed methodology, so stakeholders can have confidence in the results. DNSPs should compile and retain supporting data objectively, reliably and securely, with logical indexing and a clear audit trail. Proposals should explain how an independent party could verify the results and specify a proportionate assurance approach that balances integrity with cost.
3. **Assessment approaches** must set a clear baseline or neutral level of performance and explain how the assessment method will translate results into improvement or deterioration from that baseline. DNSPs must set a performance target that incentivises genuine improvement and reflect customer preferences, with historical performance forming the baseline for determining those targets.
4. **Rewards and penalties** must reflect the customer benefit or detriment from changes in performance. They must not encourage investment that costs consumers more than the benefit it provides them. Proposals must specify a maximum revenue at risk of no more than ±0.5%. They must also specify the incentive rate used to convert CSIS performance into a revenue adjustment. DNSPs should support both settings with credible evidence of the value customers place on the improvement or deterioration in performance.

These expectations are unchanged from previous periods. The scheme and its explanatory statement set out these expectations to guide DNSPs and consumers when engaging on and developing a proposed CSIS.

A DNSP must fully develop its proposed CSIS for 2029–34 before submitting its proposal in January 2028. This allows us to consult on and assess it alongside the other elements of the determination as a package. Recent experience has demonstrated that DNSPs face significant challenges when they rely on revised proposals to further develop or build consumer support for a CSIS after the determination process has commenced.

If a CSIS does not apply, we will instead apply one or more customer service parameters under the STPIS. DNSPs should discuss this possibility with consumers when engaging on a proposed CSIS. A DNSP that does not propose a CSIS, or whose proposal we do not accept, must provide reliable historical data needed to set the relevant STPIS customer service parameters.

3.4.2.4 Transmission STPIS Market Impact Component

For TNSPs, the STPIS includes a Market Impact Component (MIC).[88] We anticipate a new version of the STPIS MIC will be applicable to TasNetworks' transmission determination for 2029–34.

We designed the MIC to encourage TNSPs to schedule planned transmission outages at times that minimise their effect on wholesale market outcomes and, ultimately, costs to consumers.[89] It provided financial rewards or penalties based on the number of outage-related events with a material market impact, encouraging TNSPs to plan outages for lower-

88 NER version 255, cl. 6A.7.4

89 NER version 255, cl. 6A.7.4(b)(1)–(3)

demand periods and, where possible, adjust or shorten outages as market conditions changed.

In April 2025, we published version 6 of the transmission STPIS, which suspended the operation of the MIC. Changes associated with the energy transition—more renewable generation, greater congestion on radial lines and more planned outages linked to transmission investment—had substantially increased MIC events. Factors outside TNSPs' control meant most incurred maximum penalties regardless of how they managed outages, weakening the incentive to improve their behaviour. The MIC was also poorly targeted because most events that the MIC counted under its $10/MWh threshold did not affect spot prices. We therefore concluded that the MIC was no longer fit for purpose or providing the intended incentives.[90]

We established a working group with representatives of the Australian Energy Market Operator, AEMC, TNSPs, generators and consumers to develop and consider alternatives to the MIC. The purpose of the working group is to inform our considerations for a replacement MIC, including considering alternative financial incentives and a possible conduct obligation. We intend to commence a stakeholder consultation process to update the STPIS as soon as practicable following completion of the working group process.

On 14 May 2026, the AEMC made a rule change to enable the early application of a revised STPIS and disapplied the MIC from 1 January 2026.[91] After making a new STPIS, we may consult on early application arrangements to allow the application of a revised STPIS before the end of a TNSP's regulatory control period, rather than having to wait until its next determination.[92]

This means that a new version of the STPIS MIC may apply to TasNetworks before the end of the 2024–29 regulatory control period, as well as in the upcoming 2029–34 period. We would consult on the early application of any revised STPIS in accordance with the Transmission Consultation Procedures.[93]

3.5 Expenditure forecast assessment guideline

Capital expenditure (capex) and operating expenditure (opex) are core components of the forecast revenue requirements that NSPs must include in their proposals. The Expenditure Forecast Assessment Guidelines (EFA Guidelines)[94] set out the approaches we use to assess NSPs' capex and opex proposals and the information we require for the purposes of that assessment.[95]

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90 AER, *Explanatory Statement to the Electricity Transmission Service Target Performance Incentive Scheme Version 6*, April 2025.

91 NER version 255, cl. 6A.7.4A(e)–(g); AEMC, *National Electricity Amendment (Early application of a revised transmission Service Target Performance Incentive Scheme) Rule 2026 No. 4*, May 2026.

92 NER version 255, cl. 6A.7.4A(e)–(g)

93 NER version 255, cl. 6A.7.4A(b), (h), cl. 6A.20

94 AER - Expenditure forecast assessment Guidelines - October 2024 | Australian Energy Regulator (AER)

95 NER version 255, cl. 6.4.5(a), cl. 6A.5.6(a); NER (NT) version 125, cl. 6.4.5(a).

The F&A for both DNSPs and TNSPs must set out our proposed approach to the application of the EFA Guidelines in the 2029 determinations.[96] We do not have sufficient visibility of NSPs' capex and opex proposals at the time of the F&A to know definitively what tools will be best suited to their assessment. We have therefore drafted the EFA Guidelines to ensure that NSPs know enough about our assessment approaches to prepare proposals with our expectations in mind. This avoids the need to make pre-emptive judgement as to which approaches will be most appropriate in each case, and the risk that such judgment would ultimately prove disproportionate to proposals submitted in January 2028.

Capex refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS). Generally, these assets have long lives, and an NSP will recover capex from consumers over several regulatory control periods. An NSP's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.[97]

Opex refers to the operating, maintenance and other non-capital expenses NSPs incur in the provision of network services. Forecast opex is one of the building blocks we use to determine an NSP's total revenue requirement.[98] Unlike capex, NSPs recover forecast opex in full within the regulatory control period for which we approve it.

Each NSP must propose total forecast capex and opex as inputs to our determination of its revenue. The forecasts must cover expenditure needed over the relevant period to meet or manage expected demand, comply with regulatory obligations, and maintain the safety, reliability, quality and security of the network. They must also cover expenditure that contributes to Australia's greenhouse gas emissions reduction targets. These are the capex and opex objectives.[99]

We must decide whether the total forecasts of capex and opex reasonably reflect prudent and efficient costs. They must also reflect realistic expectations of future demand, cost inputs and other relevant inputs. These are the capex and opex criteria.[100]

Capex and opex are core components of our revenue determinations and significantly affect consumer prices and service outcomes. Consumer engagement and support is valuable both to NSPs in the development of their proposals, and to us in assessing them and making decisions that are in consumers' long-term interests. The extent to which a proposed forecast of capex or opex "includes expenditure to address the concerns of consumers as identified by the NSP in the course of its engagement with distribution service end users or groups representing them" is one of 12 non-exhaustive factors to which the AER must have regard in making the required assessment against the opex and capex criteria.[101]

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96 NER version 255, cl. 6.8.1(b)(2)(viii), cl. 6A.10.1A(b)(5); NER (NT) version 125, cl. 6.8.1(b)(2)(viii_

97 NER version 255, cl. 6.4.3(a)(2)–(3), cl. 6A.5.4(a)(2)–(3); NER (NT) version 125, cl. 6.4.3(a)(2)–(3).

98 NER version 255, cl. 6.4.3(a)(7), cl. 6A.5.4(a)(6); NER (NT) version 125, cl. 6.4.3(a)(7)

99 NER version 255, cl. 6.5.6(a), 6.5.7(a), cl. 6A.6.6(a), 6A.6.7(a); NER (NT) version 125, cl. 6.5.6(a), 6.5.7(a)

100 NER version 255, cl. 6.5.6(c), 6.5.7(c), cl. 6A.6.6(c), 6A.6.7(c); NER (NT) version 125, cl. 6.5.6(c), 6.5.7(c)

101 NER version 255, cl. 6.5.6(e)(3), 6.5.7(e)(3), cl. 6A.6.6(e)(5A), 6A.6.7(e)(5A); NER (NT) version 125, cl. 6.5.6(e)(5A), 6.5.7(e)(5A).

Requirements for prudency and efficiency are not at odds with the intention that proposals include expenditure to address consumers' concerns. However, consumer support alone does not guarantee that an NSP's total capex or opex forecast, or any individual project or program informing it, meets any one or more of the assessment criteria.[102]

The EFA Guidelines contain analytical tools and techniques for assessing capex and opex forecasts. Consistent with the current F&As, we intend to use the relevant tools in all 2029–34 determinations.

The assessment techniques we can use to test the prudency and efficiency of proposed expenditure include:

- economic benchmarking—using productivity measures to assess a business's overall efficiency
- category level analysis—comparing how well a business delivers services for a range of individual activities and functions, including over time and with its peers
- predictive modelling—statistical analysis to predict future spending needs,
- which we currently use to assess the need for upgrades or replacement as demand changes (augmentation capex) and expenditure needed to replace aging assets (replacement capex)
- trend analysis—forecasting future expenditure based on historical information, particularly useful for opex where spending is largely recurrent and predictable
- cost benefit analysis—assessing whether the business has chosen spending options that reflect the best value for money
- project review—a detailed engineering examination of specific proposed projects or programs
- methodology review—examining processes, assumptions, inputs and models that the business used to develop its proposal
- governance and policy review—examining the business's strategic planning, risk management, asset management and prioritisation.

We select the techniques that best suit the circumstances of each determination. The EFA Guidelines are flexible and allow us to use different techniques to assess an expenditure forecast.

We have supplemented the EFA Guidelines with more detailed guidance on specific assessment approaches and issues, much of which will be familiar to NSPs from their last determinations:

- *An interim guidance on emissions reduction*.[103]

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102 NER version 255, cl. 6.5.6(c–d), 6.5.7(c–d), cl. 6A.6.6(c–d), 6A.7.7(c–d); NER (NT) version 125, cl. .5.6(c–d), 6.5.7(c–d).

103 AER, *An interim guidance on emissions reduction*, June 2025.

- *Asset Replacement Industry Note*[104]
- *Capital expenditure assessment outline*[105]
- *DER integration expenditure guidance note*[106]
- *Guidance on amended National Energy Objectives*[107]
- *Information and Communication Technologies (ICT) Guidance Note*[108]
- *Key issues of network resilience*[109]
- *Better Resets Handbook*, which sets out expectations for capex and opex proposals as well as for NSP's engagement with consumers on those proposals.[110]

Other guidelines we have made under the NER will also inform our assessment of capex and opex proposals:

- Regulatory Investment Test for Distribution and Transmission (RIT-D and RIT-T) application Guidelines[111]
- Network Resilience Guidelines[112]

These materials and guidelines are available on our website (see links provided in footnotes). Together, they give NSPs advance notice of the assessment approaches, evidence standards and expectations of proposal-quality for the 2029–34 determinations.

3.6 Depreciation

When we roll actual capex into the RAB, we deduct depreciation.[113] The depreciation method affects incentives for efficient capex and forms part of the broader capex incentive framework.

The F&A must state whether we propose to use actual or forecast depreciation when establishing the opening RAB for the 2034–39 regulatory control period. This requirement applies to both DNSPs and TNSPs.[114]

We can use either of the following approaches:[115]

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104 AER, *Industry practice application note for asset replacement planning*, January 2019.

105 AER, *Capex assessment outline for electricity distribution determinations*, February 2020.

106 AER, *DER integration expenditure guidance note*, June 2022

107 AER, *Guidance on amended National Energy Objectives*, September 2023.

108 AER, *AER publishes guidance on non-network ICT capital expenditure assessment approach*, November 2019.

109 AER, *Note on the key issues of network resilience*, April 2022

110 AER, *Better Resets Handbook – Towards consumer-centric network proposals*, December 2021.

111 AER, *Regulatory Investment Test for Transmission and Distribution application guidelines*, November 2024.

112 NER version 255, cl. 6.4.6(a); AER, *Draft Network resilience guidelines*, September 2026.

113 NER version 255, cl. S6.2.1(e)(1), (5), cl. S6A.2.1(f)(1), (5); NER (NT) version 125, cl. S6.2.1(e)(1), (5).

114 NER version 255, cl. 6.8.1(b)(2)(ix), cl. 6A.10.1A(b)(6); NER (NT) version 125, cl. 6.8.1(b)(2)(ix), S6.2.2B(a)–(c).

115 NER version 255, cl. S6.2.2B(a), cl. S6A.2.2B(a); NER (NT) version 125, cl. S6.2.2B(a)

- **Actual depreciation:** roll forward the RAB based on actual capex less depreciation on actual capex over the regulatory period.
- **Forecast depreciation:** roll forward the RAB based on actual capex less depreciation on the forecast capex we approved for the regulatory period.

Our default position, set out in the *Capital expenditure incentive guidelines*[116], is to apply forecast depreciation. Where a CESS applies, as we propose here, NSPs will already have incentives to pursue capex efficiencies. Forecast depreciation preserves those incentives and applies the same incentive strength across the capex forecast, regardless of assets with different lives.

Exceptions may arise where:

- we do not apply a CESS, and may therefore need to strengthen the power of the capex incentive, or
- the NSP's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher-powered incentive.

In these circumstances, actual depreciation may provide stronger incentives than forecast depreciation:

- If capex exceeds forecast, actual depreciation will be higher. The RAB will be lower at the start of the next period than under forecast depreciation. The NSP will therefore earn less in future and bear more of the overspend from the current period.
- If capex is below forecast, actual depreciation will be lower. The RAB will be higher at the start of the next period than under forecast depreciation. The NSP will therefore earn more in future and retain more of the underspend benefit from the current period.

The strength of the incentive also varies with asset life under an actual depreciation approach.

Consultation question:

9) What reasons and evidence support using actual or forecast depreciation to establish these NSPs' opening RABs for 2034–39?

116 AER Capital Expenditure Incentive Guidelines - August 2025 | Australian Energy Regulator (AER)

A Reference material

The links below provide access to the F&As that applied to our 2024–29 determinations, and to our final decisions on service classification for the 2024–29 determinations, on the AER website.

Final decision service classifications are the appropriate reference point when considering additions to, or changes from, current service classifications for the DNSPs currently under review.

A.1 2024–29 Framework & Approach Papers

AER - Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy for the 2024-29 regulatory control period - July 2022

AER - Final framework and approach for Evoenergy for the 2024-29 regulatory control period - July 2022

AER - Final framework and approach for Power and Water Corporation for the 2024-29 regulatory control period - July 2022

AER - Final framework and approach for TasNetworks for the 2024-29 regulatory control period - July 2022

A.2 2024–29 Service classifications

AER - Final Decision Attachment 13 - Classification of services - Ausgrid, Endeavour Energy, Essential Energy and Evoenergy - 2024–29 Distribution revenue proposal - April 2024

AER - Final Decision Attachment 13 - Classification of services - AER - Final framework and approach for Power and Water Corporation - 2024–29 Distribution revenue proposal - April 2024

AER - Final Decision Attachment 13 - Classification of services - TasNetworks - 2024–29 Distribution revenue proposal - April 2024

Glossary

Term	Definition
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	Capital Expenditure Sharing Scheme
CSIS	Customer Service Incentive Scheme
DER	distributed energy resources
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
EFA Guidelines	Expenditure Forecast Assessment Guidelines
ENRR	Electricity Network Regulation Review
F&A	Framework and Approach paper
ICT	information and communications technology
kV	kilovolt
MIC	Market Impact Component
NEO	National Electricity Objective
NER	National Electricity Rules
NNO	non-network option
NSP	network service provider
opex	operating expenditure
PWC	Power and Water Corporation
RAB	regulatory asset base

Term	Definition
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SCS	standard control services
STPIS	Service Target Performance Incentive Scheme
TNSP	transmission network service provider