Operating expenditure step changes and output growth

Report for AusNet Services

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Contents

Tables

Executive summary

In its draft decision for AusNet Services' (AusNet) 2026-31 electricity distribution determination, the Australian Energy Regulator (AER) does not accept AusNet's total operating expenditure (opex) forecast of $1,700.3 million and adopts an alternative estimate of $1,504.2 million. The AER explains that this material difference is driven primarily by its decision to exclude or to use lower alternative estimates for ten of AusNet's 11 proposed step changes.

AusNet has asked us to review the AER's draft implementation of the base-step-trend approach for calculating the opex allowance, particularly:

- the role of each component of the base-step-trend approach in terms of how the 'step' and 'trend' components contribute to the opex objectives;
- the AER's reasoning on individual step changes as applied to AusNet; and
- the interactions between the opex criteria and the AER's opex benchmarking approach.

Regulatory framework for opex allowances

The National Electricity Rules (NER) require distribution network service providers (DNSPs) to propose the total forecast opex required to achieve five opex objectives for the regulatory control period.

In turn, the AER must accept a DNSP's opex forecast if it is satisfied that the total opex forecast for the regulatory control period reasonably reflects the opex criteria set out in the NER. The AER also must have regard to 12 operating expenditure factors as part of its decision.

The AER prefers a 'base-step-trend' approach to assessing most opex categories, which:

- begins with the estimated actual opex in the final year of the preceding regulatory control period, adjusted for the difference between efficient opex and deemed final year opex;
- applies annual percentage changes in forecast opex that account for changes in real prices, output growth and productivity in the forecast regulatory control period; and
- add step changes that account for any other efficient costs not captured in the base opex or the rate of change.

The AER's expenditure forecast assessment guideline and better resets handbook specify that step changes should not double count costs included in other elements of the opex forecast. The AER also considers that the step change component should not reflect historic average changes in the costs of regulatory obligations.

In addition, the October 2024 expenditure forecast assessment guideline also specifies that the output growth measure should reflect services provided to customers.

When calculating the trend component of opex forecasts, the AER calculates an annual rate of change for each year of the forecast regulatory control period as:

- output growth in that year; plus
- real price growth in that year; minus
- productivity growth in that year.

The AER's standard approach for forecasting output growth involves taking the weighted average of growth forecasts on three variables, namely, customer numbers, circuit length and ratcheted maximum demand.

The AER calculates the weights for each variable by referring to four econometric models that predict real opex using these three variables as explanatory variables.

Step changes in the AER's draft decision

The AER cites immateriality as one of its reasons for rejecting several of AusNet's 11 proposed step changes, namely:

- flexible services (other than flexibility services payments program): $2.5 million;
- more frequent pole inspections in response consistent with a direction by Energy Safety Victoria: $8.0 million;
- preparedness and response: $9.2 million;
- customer relationship management and communications: $15.7 million, noting that the AER also considers these costs to be discretionary expansions of existing business as usual activities; and
- insurance premium: $10.5 million.

While the AER appears to define a material step change as one that corresponds to at least 1.0 per cent of total forecast opex, we observe that the opex objectives and opex criteria do not specify a materiality threshold. It follows that the NER do not provide scope for the AER to use immateriality as a ground for rejecting a proposed step change.

The AER also considers that providing incremental opex for minor changes in specific costs encourages DNSPs to propose numerous small step changes, which we interpret as reflecting a concern that such step changes are administratively burdensome to evaluate.

However, we observe that:

- AusNet has proposed 11 step changes including two negative step changes, which does not appear to be an excessive number, given that:
  - other Victorian DNSPs have proposed six to nine step changes; and
  - SA Power Networks recently proposed for its 2025-30 regulatory period 11 step changes including two negative step changes, which the AER reduced by 1.2 per cent after accepting eight step changes in full, partially accepting one step change, and rejecting two step changes;
- proposing step changes as part of a regulatory reset does not increase administrative burden materially, since it does not involve initiating a new regulatory process outside of a periodic regulatory reset, and the AER would have already assessed each step change as part of its review of the regulatory reset; and
- the five step changes that the AER rejected for reasons that include materiality have a combined proposed value of $45.9 million, which exceeds the materiality threshold that the AER has applied in its draft decision for AusNet, ie, 1 per cent of proposed opex.

In addition, the AER has not used a consistent approach when applying its materiality threshold, ie, at least 1 per cent of total forecast opex, eg:

- the AER has not rejected AusNet's proposed $-0.7 million step change for fleet electrification, even though this negative step change is less than 1 per cent of total forecast opex and is smaller than the five positive step changes that the AER has rejected on the basis of immateriality; and
- the AER has accepted Jemena Electricity Network's proposed $4.9 million step change as a placeholder amount to meet new regulatory obligations for annual validation testing of new rapid earth fault current limiters, even though this step change represents 0.8 per cent of its proposed total forecast opex.

When addressing the potential overlaps between the step and trend components of total opex forecasts, the AER's expenditure forecast assessment guideline specifies that step changes should not double count costs included in other elements of the opex forecast, such as the trend component of the base-step-trend approach. In particular, the AER considers that the historic 'average' change in costs associated with regulatory obligations may already be accounted for in productivity growth forecasts.

However, the AER's productivity growth forecasts do not account for costs associated with material changes to regulatory obligations and other step changes. Instead, the AER's final decision on productivity growth forecasts for DNSPs demonstrates that the AER has been careful to omit the impact of such changes.

It follows that including the costs of these changes as part of the step change component of opex forecasts will not result in double counting. Instead, excluding such changes will risk that these costs not being recovered by AusNet, which will be inconsistent with the opex objectives.

New regulatory obligations for pole inspections

The AER's draft decision rejects AusNet's proposed step change for more frequent pole inspections arising from a direction issued by Energy Safety Victoria. The AER's reasoning for this decision is that the proposed additional costs:

- are immaterial;
- are covered by the trend factor in the overall opex estimate; and
- will result in efficiency benefit sharing scheme (EBSS) rewards since AusNet's base year does not account for cost savings from the previous decrease in inspection frequency in 2019.

We have discussed the first two points above, ie, that the opex objectives and opex criteria do not specify a materiality threshold, and that the AER's productivity growth estimates already exclude the impact of changes in regulatory obligations and other step changes.

In addition, the AER's own consultant, EMCa, has concluded that AusNet's proposed amount for pole inspections is prudent and efficient, while the AER itself accepts that there may be a regulatory obligation imposed for this step change. It follows that the AER's opex forecast is inconsistent with the operating expenditure objectives, which refer to the total forecast opex that the DNSP requires to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

The AER's reasoning on the third point above appears to reflect a retrospective adjustment. However, the forecast opex and EBSS provisions in the NER do not refer to such retrospective adjustments.

Proposed step changes that address opex factors

The AER's draft decision rejects AusNet's proposed step changes for preparedness and response, customer relationship management (CRM) and broad communications, and flexible services. The AER's reasons for rejecting these three proposed step changes include that the proposed incremental costs are relatively immaterial and thus are captured in the base year opex and/or trend components of total forecast opex.

We consider that the AER should be cautious about rejecting AusNet's proposed step change for CRM and broad communications, noting that:

- the AER provides no evidence to support its assertion that the proposed step changes are included in other components of the base-step-trend framework; and
- the AER must have regard to various opex factors, including the extent to which the opex forecast:
  - would efficiently reduce the risk and impact on consumers of power outages caused by severe weather events; and
  - includes expenditure to address the concerns of distribution service end users.

Furthermore, the support observed from customers and stakeholders provides further evidence that it would be efficient for AusNet to proceed with these proposed programs, which customers and stakeholders benefit from and are willing to pay for, subject to a cost assessment by the AER.

Finally, the AER rejects some of the costs of AusNet's proposed step change for flexible services and non-network solutions because it considers that the trend component of opex forecasts already provides for continued growth and adaptation.

However, such costs appear to be associated with a fundamental transformation of the business in response to Australia's ongoing transition towards renewable energy sources and the growing uptake of consumer energy resources (CER) and distributed energy resources (DER).

Furthermore, the opex factors require the AER to have regard to the relative prices of operating and capital inputs, as well as the substitution possibilities between opex and capex.

Thus, including such costs as a step change will not result in double counting with the trend component of the AER's base-step-trend approach. Conversely, rejecting this step change means that these costs will not be counted at all.

The AER's approach to benchmarking growth

The AER uses a benchmarking approach to forecast the output growth element of the trend component of opex forecasts. This involves estimating four econometric models that predict output growth based on explanatory variables that include:

- customer numbers, circuit length and ratcheted maximum demand, which the AER uses to forecast output growth for each DNSP; and
- share of underground cables, an annual time trend, and dummy variables for country and DNSP, which are not used to forecast output growth.

We consider that the AER's approach:

- is unlikely to provide an accurate forecast of the increase in AusNet's opex associated with customer and network growth and the expansion of services over the 2026-31 regulatory period; and
- will not fund the step changes that the AER purports to fund.

This is because the AER's four econometric models use a backward-looking approach that relies on historical data, but the opex objectives and opex criteria refer to the recovery of forward-looking costs that may differ materially from historical observations outside of a business-as-usual environment.

Furthermore, the AER first consulted on its benchmarking approach in 2012 and has used this approach since its first annual benchmarking report in 2014. However, Australia's energy system and the national electricity market have changed considerably since then, such that the AER's benchmarking models are likely to have reduced explanatory power because:

- the energy transition and the uptake of CER and DER are likely to be important drivers of DNSPs' output growth but are not captured directly in the AER's explanatory variables; and
- the overall associations between DNSPs' output growth and the AER's explanatory variables are likely to have weakened and/or rebalanced considerably and will continue to do so.

For example, the AER's draft decision assigns 40.9 per cent weight to ratcheted maximum demand when forecasting AusNet's output growth, followed by customer numbers at 39.1 per cent weight and circuit length at 20.0 per cent weight.

However, it is unclear whether ratcheted maximum demand remains the most important driver of output growth, given the change in energy consumption patterns since 2012, with data centre uptake becoming a key driver of energy demand.

While CER and gas electrification tend to contribute less to energy consumption growth compared to the corresponding contribution from data centres, the former contribute heavily to growth in required opex. For example:

- data centres tend to have stable energy demand, while CER and DER exhibit daily variations in two-way energy flows that require more voltage regulation, more frequent maintenance for the electricity network, and more extensive forecasting and planning; and
- data centres tend to be located in or near population centres, while CER and DER can be located in dispersed locations that may be far from population centres, which increases the costs of monitoring inverter compliance, as well as increasing customer support costs and the costs of operational responses to minimum system load events.

Consequently, the high weight that the AER assigns to ratcheted maximum demand may not be sufficiently granular for forecasting output growth for the 2026-31 regulatory period, such that the weights assigned across each of the AER's explanatory variables may need to be rebalanced.

It follows that AusNet's lower growth in forecast energy demand compared to the other four Victorian DNSPs does not necessarily translate to a lower growth in AusNet's required opex over the 2026-31 regulatory period. For example, AusNet may have to incur higher opex to maintain network resilience as a service to its customers, but this variation in costs will not be captured in the three explanatory variables that the AER currently uses to forecast output growth for each DNSP.

This also means that the AER's approach for forecasting output growth may be inconsistent with the October 2024 expenditure forecast assessment guideline, which requires output measures to reflect services provided to customers.

The AER can address the price reset-specific issues outlined above by accepting the step changes proposed by AusNet.

However, over the longer term, the AER may need to revise or replace its base-step-trend approach in response to the change in business conditions associated with the ongoing transition towards renewable energy sources and the growing uptake of CER and DER. The New Zealand Commerce Commission (NZCC) acknowledged this issue in its November 2024 decision setting out the fourth default price quality path for electricity distribution businesses in New Zealand.

Three potential options that the AER can adopt to improve the accuracy of its output growth forecasts over the longer term are:

- modifying its econometric model specifications to include different explanatory variables that capture the key drivers of future output growth, eg, the AER's export services network performance report includes the proportion of customers using export services and the proportion of energy delivered by exports, although we note that this retains a backward-looking approach;
- adopting different econometric models such as those previously proposed by the New South Wales DNSPs for the 2014-19 regulatory period, eg, fixed effects and random effects panel data models; and
- assigning less weight to the outputs of its econometric benchmarking models and taking more consideration of the operating environment for each DNSP.

One example of the first point above is the New Zealand Commerce Commission's (NZCC) approach that includes capital expenditure average growth rate as an explanatory variable when forecasting non-network opex growth for electricity distribution businesses.

In that decision, the NZCC also considered the second point above but did not implement it after concluding that the inclusion of ‘fixed effects’ did not improve the fit of its output growth model.

The Essential Services Commission of South Australia’s (ESCOSA) approach for SA Water provides an example of the third point above, whereby ESCOSA calculated SA Water’s opex allowance by including forecast output growth as a step change.

1. Introduction

In its draft decision for AusNet Services' (AusNet) 2026-31 electricity distribution determination, the Australian Energy Regulator (AER) does not accept AusNet's total operating expenditure (opex) forecast of $1,700.3 million and adopts an alternative estimate of $1,504.2 million. The AER explains that this material difference is driven primarily by its decision to exclude or to use lower alternative estimates for ten of AusNet's 11 proposed step changes.[1]

AusNet has asked us to review the AER's draft implementation of the base-step-trend approach for calculating the opex allowance, particularly:

- the role of each component of the base-step-trend approach in terms of how the 'step' and 'trend' components contribute to the opex objectives;
- the AER's reasoning on individual step changes as applied to AusNet; and
- the interactions between the opex criteria and the AER's opex benchmarking approach.

We have structured this report as follows:

- section 2 summarises the regulatory framework for opex allowances and the AER's base-step-trend approach for forecasting opex;
- section 3 discusses the AER's draft decision on AusNet's proposed opex step changes; and
- section 4 discusses the AER's approach to opex benchmarking.

[1] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 1.

2. Regulatory framework for opex allowances

In this section we summarise the regulatory framework for opex allowances, particularly:

- the opex criteria and opex objectives set out in the NER; and
- the AER's preferred base-step-trend approach for developing opex forecasts.

This discussion provides background for sections 3 and 4 below, where we discuss:

- the AER's draft decision on opex step changes for AusNet's 2026-31 electricity distribution determination; and
- the appropriateness of the AER's benchmarking approach in the context of Australia's ongoing transition to renewable energy sources.

2.1 Opex criteria and opex objectives

The National Electricity Rules (NER) require distribution network service providers (DNSPs) to propose the total forecast opex required to achieve the opex objectives for the regulatory control period. The NER specifies five opex objectives, two of which are to:[2]

- meet or manage the expected demand for standard control services over that period; and
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

In turn, the AER must accept a DNSP's opex forecast if it is satisfied that the total opex forecast for the regulatory control period reasonably reflects the opex criteria, which are:[3]

- the efficient costs of achieving the opex objectives;
- the costs that a prudent operator would require to achieve the opex objectives; and
- a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the opex objectives.

That is, the NER requires the AER to evaluate the prudence and efficiency of a DNSP's opex forecast in totality. The AER cannot evaluate each individual opex component in isolation without considering the DNSP's total opex forecast.

The AER also must have regard to 12 operating expenditure factors as part of its decision. Some of these factors include:[4]

- the AER's most recent annual benchmarking report;
- the extent to which the opex forecast includes expenditure to address the concerns of distribution service end users as identified through the DNSP's engagement with them or the groups representing them; and
- the relative prices of operating and capital inputs, as well as the substitution possibilities between opex and capital expenditure (capex).

[2] The other opex objectives pertain to quality, reliability, security of supply, safety of the distribution system and the achievement of emissions reduction targets. See: NER version 236, clause 6.5.6(a).

[3] NER version 236, clause 6.5.6(c).

[4] NER version 236, clause 6.5.6(e).

We discuss the opex criteria and opex objectives further in section 3 below, where we discuss the AER's draft assessment of opex step changes for AusNet's 2026-31 electricity distribution determination.

2.2 Base-step-trend approach for forecasting opex

The AER prefers a 'base-step-trend' approach to assessing most opex categories, which:[5]

- begins with the estimated actual opex in the final year of the preceding regulatory control period, adjusted for the difference between efficient opex and deemed final year opex;
- applies annual percentage changes in forecast opex that account for changes in real prices, output growth and productivity in the forecast regulatory control period; and
- add step changes that account for any other efficient costs not captured in the base opex or the rate of change.

We set out the AER's base-step-trend formula in box 2.1 below.

Box 2.1: Formula for base-step-trend assessment approach

$$Opex_t = \prod_{i=1}^{t}(1 + rate\ of\ change_i) \times \left(A_f^* - efficiency\ adjustment\right) \pm step\ changes_t$$

Where:

- *rate of change*$_i$ is the annual percentage rate of change in year *i*;
- A_f^* is the estimated actual opex in the final year of the preceding regulatory control period;
- *efficiency adjustment* is the difference between efficient opex and deemed final year opex; and
- *step changes*$_t$ is the determined step change in year *t*.

Source: AER, Expenditure forecast assessment guideline for electricity distribution, October 2024, p 22.

In sections 2.2.1 and 2.2.2 below we set out two aspects of the base-step-trend approach, namely:

- the distinction between the step and trend components; and
- the use of benchmarking in the trend component.

2.2.1 Distinction between the step and trend components

The AER's expenditure forecast assessment guideline specifies that step changes should not double count costs included in other elements of the opex forecast, eg, the costs of:[6]

- increased volume or scale compensated through the output measure in the rate of change;
- increased regulatory burden over time, which forecast productivity growth may already account for; and
- discretionary changes in inputs, in that efficient discretionary changes in inputs that are not required to increase output should normally have a net negative impact on expenditure.

[5] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, p 22.

[6] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, pp 24-25.

Conversely, a step change may be included for the costs of efficiently substituting capex with opex.[7]

Regarding the second point above, the AER explains that the step change component should not reflect historic average changes in the costs of regulatory obligations:[8]

> Step changes should not double count the cost of increased regulatory burden over time, which forecast productivity growth may already account for. We will only approve step changes in costs if they demonstrably do not reflect the historic 'average' change in costs associated with regulatory obligations. We will consider what might constitute a compensable step change at resets, but our starting position is that only exceptional events are likely to require explicit compensation as step changes. Similarly, forecast productivity growth may also account for the cost increases associated with good industry practice.

The AER's better resets handbook also states that:[9]

- the number of forecast step changes is limited to a few well justified ones, or none at all; and
- step changes should be explored with customers.

The AER further states in the better resets handbook its expectations that:[10]

- a **new regulatory obligation step change** should:
  - be clearly linked to the new regulatory obligation and represent a major upward step to comply with it;
  - have an impact on the costs of providing prescribed network services and can be demonstrated that it is not capable of being managed otherwise under forecast opex through in-built provisions under output, price and productivity growth; and
  - not double count costs;
- a **capex/opex substitution step change** should:
  - be supported by thorough cost-benefit analysis;
  - estimate avoided capex accurately that more than offsets the increase in opex in net present value terms, ie, efficient substitution; and
  - not double count costs; and
- a **step change driven by major external factor(s) outside the control of a business** should:
  - have an impact on the costs of providing prescribed network services and can be demonstrated that it is not capable of being managed otherwise under forecast opex, including through inbuilt provisions under output, price and productivity growth;
  - where it involves incurring costs in complex areas or markets, be accompanied by an expert report that includes analysis of options, market outlook and opinion on the reasonableness of the proposed step change; and
  - not double count costs.

In section 3 below we discuss the AER's assessment of the step change component in its draft decision for AusNet.

[7] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, p 25.

[8] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, p 24.

[9] AER, *Better resets handbook: towards consumer centric network proposals*, July 2024, p 26.

[10] AER, *Better resets handbook: towards consumer centric network proposals*, July 2024, box 1.

2.2.2 The role of benchmarking in the trend component

The AER calculates an annual rate of change for each year of the forecast regulatory control period as:[11]

- output growth in that year; plus
- real price growth in that year; minus
- productivity growth in that year.

Regarding output growth, the AER's standard approach for forecasting output growth involves taking the weighted average of growth forecasts on three variables, namely, customer numbers, circuit length and ratcheted maximum demand. The AER calculates the weights for each variable by referring to four econometric models that predict real opex using these three variables as explanatory variables, alongside other explanatory variables that are not used to forecast output growth.[12]

The AER first consulted on this approach in 2012 and has used it since its first annual benchmarking report in 2014.[13]

The AER's October 2024 expenditure forecast assessment guideline further specifies that the output measures should be the same as the measures used to forecast productivity growth, and should:[14]

- align with the National Electricity Law and NER objectives;
- reflect services provided to customers;
- be significant; and
- not be adjusted for economies of scale, if any.

In section 4 below we discuss the AER's forecast of output growth in its draft decision for AusNet.

The AER and AusNet have used similar approaches for calculating real price growth and productivity growth, ie:

- when calculating real price growth, the AER and AusNet both assign 59.2 per cent weight to labour price growth and 40.8 per cent to non-labour price growth (zero real price growth) and refer to the same sources for forecasting labour price growth, although the AER obtains a slightly higher forecast of real price growth since it has used a more recent estimate from Deloitte Access Economics;[15] and
- the AER and AusNet both use an average productivity growth of 0.5 per cent per year, which is consistent with the AER's standard approach set out in a report dated March 2019.[16]

We do not discuss the forecasts of real price growth and productivity growth further in this report, other than to discuss in section 3.2 below the potential overlaps between step changes and productivity growth.

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[11] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, p 23.

[12] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.5. Quantonomics, *Economic benchmarking results for the Australian Energy Regulator's 2024 DNSP annual benchmarking report*, 15 October 2024, pp 144-147.

[13] See: AER, *Electricity distribution network service providers*, Annual benchmarking report, November 2014, pp 5, 23.

[14] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, pp 23-24.

[15] The AER and AusNet both forecast average annual price growth that round to 0.6 per cent. However, the AER's forecast is 0.03 per cent higher, resulting in a total opex estimate that is approximately $1.6 million higher. See: AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 13-14.

[16] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 16. AER, *Forecasting productivity growth for electricity distributors*, Final decision paper, March 2019, p 13.

3. Step changes in the AER's draft decision

In this section we discuss the AER's draft decision on AusNet's proposed step changes, namely:

- the AER's assessment of materiality, noting that the NER do not specify a materiality threshold for forecast opex and the AER has not applied a consistent approach for assessing materiality; and
- the potential overlaps between the proposed step changes and the trend component of the base-step-trend approach, noting that the AER's productivity estimates already exclude the cost impact of regulatory changes and other step changes.

3.1 Materiality of step changes

The AER cites immateriality as one of its reasons for rejecting five of AusNet's 11 proposed step changes, namely:[17]

- flexible services (other than flexibility services payments program): $2.5 million;
- more frequent pole inspections in response consistent with a direction by Energy Safety Victoria: $8.0 million;
- preparedness and response: $9.2 million;
- customer relationship management and communications: $15.7 million, noting that the AER also considers these costs to be discretionary expansions of existing business as usual activities; and
- insurance premium: $10.5 million.

We explain in sections 3.1.1 to 3.1.2 below that:

- the opex objectives and opex criteria do not specify materiality thresholds; and
- the AER has not assessed materiality consistently.

3.1.1 No materiality threshold for assessing total opex forecast for the regulatory control period

We discuss in section 2.2.1 above that the better resets handbook states the AER's expectation that a new regulatory obligation step change should represent a 'major upward step' to comply with a clearly linked new regulatory obligation.[18]

While the AER does not define or provide guidance about the minimum threshold for a 'major upward step', the AER's draft decision appears to define a material step change as one that corresponds to at least 1.0 per cent of total forecast opex. This can be seen when the AER refers to a 1.0 per cent threshold for rejecting AusNet's proposed step change for preparedness and response:[19]

> Given the relative immateriality of the step change (<1.0%), we consider that the opex associated with this expansion over the next period of existing functions is accounted under the base and trend components of our opex forecasting framework.

However, we observe that the opex objectives and opex criteria do not specify a materiality threshold. As we explain in section 2.1 above:

[17] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 17-19, 19-21, 26-27, 29-31, 32.

[18] AER, *Better resets handbook: towards consumer centric network proposals*, July 2024, box 1.

[19] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 27.

- the NER requires the DNSP to propose the total forecast opex that it requires to meet the opex objectives over the regulatory control period;[20] and
- the AER must accept a DNSP's total forecast opex for the regulatory control period if it meets the opex criteria, ie, that it is prudent, efficient and realistic.[21]

It follows that the NER do not provide scope for the AER to use immateriality as a ground for rejecting a proposed step change.

The AER considers that providing incremental opex for minor changes in specific costs encourages DNSPs to propose numerous small step changes.[22] While the AER has not explained why proposing numerous small step changes contradicts the opex objectives or the opex criteria, we interpret the AER's view as reflecting a concern that such step changes are administratively burdensome to evaluate.

However, we observe that:

- AusNet has proposed 11 step changes including two negative step changes, which does not appear to be an excessive number, given that:
  - other Victorian DNSPs have proposed six to nine step changes;[23] and
  - SA Power Networks recently proposed for its 2025-30 regulatory period 11 step changes including two negative step changes, which the AER reduced by 1.2 per cent after accepting eight step changes in full, partially accepting one step change, and rejecting two step changes;[24] and
- proposing step changes as part of a regulatory reset does not increase administrative burden materially.

Regarding the second point above, we note that many of the materiality thresholds in the NER relate to the initiation of a new regulatory process outside the regulatory reset process. For example:

- the regulatory test for distribution applies to capital costs exceeding $7 million;[25] and
- capex reopeners can only be initiated if rectification costs during the regulatory control period exceed 5 per cent of the DNSP's regulatory asset base for the first year of the regulatory control period, in addition to other requirements.[26]

Initiating a new regulatory process is administratively costly, which makes it sensible to set cost thresholds for such processes to reduce administrative burden.

However, this reasoning does not apply to the regulatory reset process, since:

- DNSPs must undergo regulatory resets regardless of the number of step changes that they propose; and
- the AER would have already assessed each step change as part of its review of the regulatory reset.

[20] NER version 236, clause 6.5.6(a).

[21] NER version 236, clause 6.5.6(c).

[22] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 27.

[23] Jemena Electricity Networks proposed nine step changes and CitiPower proposed six step changes, while Powercor and United Energy proposed seven step changes each. See: AER, *Jemena electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1. AER, *CitiPower electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1. AER, *Powercor electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1. AER, *United Energy electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1.

[24] AER, *SA Power Networks Electricity Distribution Determination 2025 to 2030 (1 July 2025 to 30 June 2030), Attachment 6 Operating expenditure*, September 2024, table 6.1.

[25] AER, *2024 RIT and APR cost thresholds review*, Final determination, November 2024, p 1.

[26] NER version 236, clause 6.6.5(a)(4)(i).

Thus, the incremental administrative burden associated with an additional step change is immaterial compared to that associated with initiating a new regulatory process, which may explain the lack of a materiality threshold in the opex objectives and opex criteria.

Furthermore, the corollary of the AER's reasoning is that disallowing step changes on the basis of materiality will encourage DNSPs to consolidate their step changes to meet the AER's materiality threshold. This may reduce transparency for stakeholders without reducing administrative burden for the AER if DNSPs continue to provide supporting information to the same level of detail.

For example, we observe in the context of ElectraNet's 2023-28 regulatory period that:

- the AER's draft decision rejected ElectraNet's proposed $3.9 million 'rule changes' step change for reasons that include materiality, since ElectraNet's proposed step change only made up 0.6 per cent of its total opex forecast for the 2023-28 period;[27]
- ElectraNet reproposed an updated $21.4 million rule changes step change that was broader in scope and combined three components, ie, capability uplift, transmission licence fee and renewable electricity zones design reports;[28] and
- the AER's final decision includes a $2.5 million step change that reflects only the transmission licence fee component of ElectraNet's reproposed step change.[29]

In this case, the AER's materiality threshold on ElectraNet's proposed rule changes step change would not have reduced administrative burden. The AER ended up having to review all three components of ElectraNet's reproposed consolidated step change, such that its administrative burden would not have differed materially from that of a counterfactual where ElectraNet proposed the three components as separate step changes instead of as a single combined step change.

We also observe that the AER's final decision for ElectraNet approved two step changes for which the AER's alternative estimate made up less than one per cent of the total opex allowance. In table 3.1 below we show the four step changes in ElectraNet's revised proposal, along with the AER's corresponding final alternative estimates.

Table 3.1: Step changes in ElectraNet transmission determination 2023-28

	ElectraNet revised proposal	AER final decision	% of total opex in final decision
Cyber security	24.6	18.2	2.70%
Rule changes	21.4	2.5	0.37%
Insurance	6.0	6.0	0.89%
IFRS (intangible assets)	48.7	48.7	7.22%
Total opex incl debt raising costs	**701.1**	**673.8**	**100%**

Source: AER, ElectraNet transmission determination 1 July 2023 to 30 June 2028, Attachment 6 – Operating expenditure, Final decision, April 2023, table 6.1.

[27] AER, *ElectraNet transmission determination 2023 to 2028 (1 July 2023 to 30 June 2028), Attachment 6 Operating expenditure*, Draft decision, September 2022, p 24.

[28] AER, *ElectraNet transmission determination 1 July 2023 to 30 June 2028, Attachment 6 – Operating expenditure*, Final decision, April 2023, pp 15-16.

[29] AER, *ElectraNet transmission determination 1 July 2023 to 30 June 2028, Attachment 6 – Operating expenditure*, Final decision, April 2023, pp 15-16.

Notwithstanding, we observe that AusNet's five step changes that the AER rejected for reasons that include materiality have a combined proposed value of $45.9 million. This combined value exceeds the materiality threshold that the AER has applied in its draft decision for AusNet, ie, 1 per cent of proposed opex.

Consequently, the AER's draft decision to reject these five step changes also represents a material reduction of AusNet's proposed opex compared to that required to achieve the opex objectives and opex criteria.

Table 3.2: AusNet's five step changes as a percentage of total proposed opex

Step change	AusNet's initial proposal	Percentage of total opex
Flexible services (other than flexibility services payments program)	$2.5 million	0.15%
ESV more frequent pole inspections	$8.0 million	0.47%
Preparedness and response	$9.2 million	0.54%
CRM and communications	$15.7 million	0.92%
Insurance premium	$10.5 million	0.62%
Total	**$45.9 million**	**2.70%**
Total excluding insurance premium	**$35.4 million**	**2.08%**
Total opex	$1,700.3 million	100%

Source: AER, AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1, pp 17-19. HoustonKemp analysis.

We note that Ausgrid has previously made a similar observation regarding a proposed step change for insurance premiums in its revised proposal for its 2024-29 regulatory period, ie, that there is no basis in the National Electricity Law or the NER to apply a materiality threshold to opex step changes.[30]

The AER's final decision rejects the proposed insurance premium step change in Ausgrid's revised proposal because:[31]

- the AER's draft decision to reject the step change was not based solely on the expenditure being immaterial as a proportion of total opex;
- the AER's starting position as set out in the expenditure forecast assessment guideline is that only exceptional events are likely to require explicit compensation as step changes; and
- the proposed step change to insurance premium costs is likely to be offset by other non-labour costs rising by less than the consumer price index and therefore is captured in the non-labour price component of the rate of change.

In contrast, the AER's draft decision for AusNet rejects the 'preparedness and response' step change solely because of immateriality, while citing overlaps with other base-step-trend components when rejecting the step changes for more frequent pole inspections, customer relationship management and communications, and 'insurance premium.'[32] We discuss these proposed step changes further in section 3.2 below.

[30] AER, *Ausgrid determination 2024 to 2029 (1 July 2024 to 30 June 2029), Attachment 6 Operating expenditure*, Final decision, April 2024, p 18.

[31] AER, *Ausgrid determination 2024 to 2029 (1 July 2024 to 30 June 2029), Attachment 6 Operating expenditure*, Final decision, April 2024, p 19.

[32] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 26-27, 29-31, 32.

3.1.2 Inconsistent use of materiality threshold

The AER has not used a consistent approach when applying its materiality threshold, ie, at least 1 per cent of total forecast opex.

We explain above that the AER cites immateriality as one of its reasons for rejecting five of AusNet's 11 proposed step changes with proposed costs ranging from $8.0 million to $10.5 million.[33]

However, the AER conversely has not rejected AusNet's proposed $-0.7 million step change for fleet electrification,[34] even though this negative step change:

- is less than 1 per cent of total forecast opex; and
- is smaller than the five positive step changes that the AER has rejected on the basis of immateriality.

Instead, the AER includes this proposed negative step change after assessing that it reflects a prudent and efficient trade-off between opex and capex.[35] Notwithstanding this contradiction in the AER's application of its materiality threshold, we observe that the AER's assessment of the proposed negative step change for fleet electrification is consistent with the NER, ie:

- the AER's assessment of prudence and efficiency is consistent with the opex criteria;[36] and
- the AER's consideration of the trade-off between opex and capex matches one of the opex factors that requires the AER to have regard to the relative prices of operating and capital inputs.[37]

The AER also has not applied its materiality threshold consistently across its draft decisions for the five Victorian DNSPs. In particular, the AER has accepted Jemena Electricity Network's proposed $4.9 million step change as a placeholder amount to meet new regulatory obligations for annual validation testing of new rapid earth fault current limiters, even though this step change represents 0.8 per cent of its proposed total forecast opex.[38]

The AER has not referred to a materiality threshold when assessing this proposed step change.

3.2 Potential overlaps between the step and trend components

We explain in section 2.2.1 above that the AER's expenditure forecast assessment guideline specifies that:[39]

- step changes should not double count costs included in other elements of the opex forecast; and
- step changes should not reflect historic average changes in the costs of regulatory obligations.

In section 3.2.1 below we explain that the AER's productivity estimates already exclude the cost impact of regulatory changes and other step changes.

We then discuss in sections 3.2.2 to 3.2.3 below how the AER has applied the above reasoning to four of AusNet's proposed step changes, namely:

[33] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 19-21, 26-27, 29-31, 32.

[34] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 21-22.

[35] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 21-22.

[36] NER version 236, clause 6.5.6(c).

[37] NER version 236, clause 6.5.6(e)(5).

[38] AER, *Jemena electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1, pp 29-30.

[39] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, pp 24-25.

- more frequent pole inspections, which is a new regulatory obligation that should be included as a step change, taking into account AER precedent on the materiality of cost changes; and
- preparedness and response, customer relationship management and broad communications, and flexible services, which are new obligations arising by agreement after engaging with customers.

We do not discuss the AER's reasoning on the flexible services step change. However, we note that the AER accepts that it is prudent for AusNet to improve its dynamic management capabilities to integrated and operate in a growing CER environment.[40] We explain in section 4.1.1 below that the AER's benchmarking approach for forecasting output growth does not account for the energy transition and the uptake of CER and DER.

We also note that these five proposed step changes have a combined proposed value of $45.9 million or approximately 2.7 per cent of AusNet's opex proposal.

3.2.1 AER's productivity estimates exclude material regulatory changes and other step changes

We explain in section 2.2.1 above that the AER's expenditure forecast assessment guideline specifies that step changes should not double count costs included in other elements of the opex forecast, such as the trend component of the base-step-trend approach. In particular, the AER considers that the historic 'average' change in costs associated with regulatory obligations may already be accounted for in productivity growth forecasts.[41]

However, the AER's productivity growth forecasts were selective in the period assessed to remove the impact of new regulatory obligations that resulted in a negative productivity growth.

Instead, the AER's final decision on productivity growth forecasts for DNSPs demonstrates that the AER has been careful to omit the impact of such changes when developing its forecasts. In that decision, the AER explains that the productivity growth factor captures the impact of factors that affect 'business-as-usual' operations, such as changes to technology and management practices:[42]

> This review concerns the productivity growth factor that is included within the trend component of our opex forecasting approach. **This productivity growth factor captures the improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.** Another way of putting this is that it reflects the improvement in the efficient production frontier within the electricity distribution industry. **This comes from such things as new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.** (emphasis added)

The AER goes on to explain that it does not include material changes in regulatory obligations when estimating productivity growth since doing so would compensate distributors twice for new regulatory obligations:[43]

> Since 2013, we have applied a productivity growth factor of zero per cent in all our determinations for electricity distributors in the NEM. **We estimated that the productivity growth of the electricity distribution industry had been negative on average since 2006 but noted that this productivity decline reflected the major changes in regulatory obligations relating to reliability and safety that occurred prior to 2011.** These regulatory obligation changes increased the inputs but not the outputs we measured in our productivity analyses, and for which we had allowed explicit opex step changes in our opex forecasts.

[40] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 18-19.

[41] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, pp 24-25.

[42] AER, *Forecasting productivity growth for electricity distributors*, Final decision paper, March 2019, p 7.

[43] AER, *Forecasting productivity growth for electricity distributors*, Final decision paper, March 2019, p 8.

> **A negative productivity growth factor of this sort would have provided additional opex to the amount provided for in step changes. This would have had the effect of compensating distributors twice for the new regulatory obligations.** Similarly, we did not consider that a prudent and efficient distributor would reduce its productivity unless it was required to meet new uncontrollable obligations. (emphasis added)

Finally, the AER states that it adopts a shorter estimation period to ensure that its productivity estimates are not contaminated by material step changes and other changes in regulatory obligations:[44]

> **This leaves us with forecasting productivity using productivity measured on the period following the step change period.** Here we are mindful that the periods of 2012–16 and 2012–17 are relatively short to form a single estimate of productivity growth that may be achievable going forward. This is recognised by Economic Insights. **While there are no clear and material changes in regulatory obligations over this period, there may be variations in productivity year to year that will affect the productivity trend over this period of time.** (emphasis added)

Since the AER already excludes the impact of material changes in regulatory obligations and other step changes when estimating productivity growth, it follows that including the costs of such changes as part of the step change component of opex forecasts will not result in double counting.

Instead, excluding such material changes will risk these costs not being recovered by AusNet, which will be inconsistent with the opex objectives that refer to the total forecast opex required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[45]

We examine this issue further in sections 3.2.2 and 3.2.3 below, where we discuss some of the step changes that the AER has rejected in its draft decision for AusNet.

3.2.2 New regulatory obligations for pole inspections

The AER's draft decision rejects AusNet's proposed step change for more frequent pole inspections arising from a direction issued by Energy Safety Victoria. The AER's reasoning for this decision is that the proposed additional costs:[46]

- are immaterial;
- are covered by the trend factor in the overall opex estimate; and
- will result in efficiency benefit sharing scheme (EBSS) rewards since AusNet's base year does not account for cost savings from the previous decrease in inspection frequency in 2019.

We have discussed the first point regarding the AER's materiality threshold in section 3.1 above.

Regarding the second point, we observe that the AER has applied a different line of reasoning compared to that set out in the expenditure forecast assessment guideline.[47] Specifically, the AER has not shown that the proposed step change for more frequent pole inspections:

- double counts costs included in other elements of the opex forecast; and/or
- reflects historic average changes in the costs of regulatory obligations.

Instead, the AER asserts that AusNet can manage the additional cost through the trend component of the opex forecast, but provides no evidence to support this assertion and does not explain whether or how this

[44] AER, *Forecasting productivity growth for electricity distributors*, Final decision paper, March 2019, p 38.

[45] NER version 236, clause 6.5.6(a)(2).

[46] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 19-21.

[47] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, pp 24-25.

additional cost corresponds to growth in output, price and/or productivity.[48] We also explain in section 3.2.1 above that the AER's productivity growth estimates already exclude the impact of changes in regulatory obligations and other step changes.

In addition, the AER's own consultant, EMCa, has concluded that AusNet's proposed amount for pole inspections is prudent and efficient, while the AER itself accepts that there may be a regulatory obligation imposed for this step change.[49]

It follows that the AER's opex forecast is inconsistent with the operating expenditure objectives, which include a reference to the total forecast opex that the DNSP requires to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[50]

The AER's reasoning on the third point above appears to reflect a retrospective adjustment. Specifically, the AER notes a prior decrease in inspection frequency in 2019 from five years to six years that is not reflected in AusNet's proposed base year, although AusNet states that it has not benefitted financially from this prior change:[51]

> **Through AusNet's engagement with an Opex and Benchmarking Panel, it was raised that AusNet may have benefitted financially from a prior decrease in inspection frequency (from five to six years) that occurred in 2019, then the proposed step change for 2026–31 would prevent customers from sharing in those benefits through the EBSS.** In response, AusNet stated it did not financially benefit from the previous change as inspection costs increased in 2018-19. However, from the available information provided, we have found inspection costs to have incurred lower opex costs in 2020–2024 period after inflation adjustments, supporting the panel's view of EBSS efficiencies in the current regulatory period. (emphasis added)

The AER thus considers it appropriate to reject the proposed step change on the basis that AusNet would receive a net gain through the EBSS because the base year does not account for cost savings from the previous decrease in inspection frequency in 2019.[52]

However, the forecast opex and EBSS provisions in the NER do not refer to such retrospective adjustments. Instead:

- clause 6.5.6(e)(7) states that one of the opex factors relates to whether the DNSP's opex forecast is consistent with incentive schemes that apply to the DNSP, including the EBSS; and
- clause 6.5.8(a) defines the EBSS as referring to efficiency gains and losses arising from differences between the actual opex of a DNSP and the forecast opex accepted or substituted by the AER for a regulatory control period.[53]

Consistent with the AER's ex ante regulatory framework, neither clause states that the AER should adjust its opex forecast with the effect of making retrospective adjustments that compensate or penalise DNSPs for benefits enjoyed or costs incurred due to changes in regulatory obligations that occurred in the middle of previous regulatory periods.

[48] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 19-21.

[49] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 20.

[50] NER version 236, clause 6.5.6(a)(2).

[51] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 20.

[52] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 21.

[53] NER version 236, clause 6.5.8(a).

3.2.3 Proposed step changes that address opex factors

The AER's draft decision rejects AusNet's proposed step changes for preparedness and response, customer relationship management (CRM) and broad communications, and flexible services. The AER's reasons for rejecting these three proposed step changes include that the proposed incremental costs are relatively immaterial and thus are captured in the base year opex and/or trend components of total forecast opex.[54]

Regarding the proposed step change for preparedness and response, the AER:[55]

- accepts that it is prudent for AusNet to improve its dynamic management capabilities and to improve its operational capability in emergency response; and
- notes that stakeholders emphasise network resilience as crucial in the evolving energy landscape, with grid electrification and climate change as the primary drivers.

However, the AER asserts that the costs associated with these proposed step changes are immaterial and thus are included in the base and/or trend components of the base-step-trend framework, although the AER provides no evidence to support this assertion and does not explain how the additional costs are captured in output growth, real price growth and/or productivity growth.[56]

Without such evidence, the AER's opex forecast will be inconsistent with:

- the opex objectives and criteria, since it will not provide AusNet with the opex allowance required to fulfil the fourth limb of the opex objectives, ie, maintaining the safety of the distribution system through the supply of standard control services;[57] and
- the opex factors, which require the AER to have regard to the relative prices of operating and capital inputs, as well as the substitution possibilities between opex and capex.[58]

Regarding the proposed step change for CRM and broad communications, the AER considers that there is evidence of customer support for AusNet improving its communication and coordination with commercial and industrial customers. Nevertheless, the AER views the proposed step change as a discretionary expansion of existing business-as-usual activities that do not meet the step change criteria. The AER ultimately rejects the proposed step change because it considers the relatively immaterial forecast increase is captured in the base and trend components of total forecast opex.[59]

We consider that the AER should be cautious about rejecting these proposed step changes. In particular, the NER requires the AER to have regard to various opex factors that include:[60]

- the extent to which the opex forecast would efficiently reduce the risk and impact on consumers of power outages caused by severe weather events, which applies to the proposed step change for preparedness and response; and
- the extent to which the opex forecast includes expenditure to address the concerns of distribution service end users as identified by the DNSP in the course of its engagement with distribution service end users

[54] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 17-19, 26-27, 29-31.

[55] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 26-27.

[56] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 26-27.

[57] NER version 236, clause 6.5.6 (a)(4).

[58] NER version 236, clause 6.5.6(e)(5)-(6).

[59] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 30-31.

[60] NER version 236, clause 6.5.6 (e)(3)-(e)(4).

or groups representing them, which applies to the proposed step changes for preparedness and response and for CRM and broad communications.

Furthermore, the support observed from customers and stakeholders provides further evidence that it would be efficient for AusNet to proceed with these proposed programs, which customers and stakeholders benefit from and are willing to pay for, subject to a cost assessment by the AER. We note that the AER has not raised any efficiency concerns in its assessment of this step change.[61]

Conversely, refusing to approve and provide funding for these proposed programs would result in inefficiency and deadweight loss, since AusNet will not receive funding for these programs and thus would be unable to deliver the services that customers value.

Finally, the AER rejects some of the costs of AusNet's proposed step change for flexible services and non-network solutions because it considers that the trend component of opex forecasts already provides for continued growth and adaptation:[62]

> For the remaining costs, we consider it prudent for AusNet to improve its dynamic management capabilities. We consider this a necessary evolution of the network to integrate and operate in a growing CER environment. However, we consider these costs to inherently already be provided to AusNet through our base-step-trend forecasting approach. That is, our opex forecasting approach provides for an uplift through the rate of change factor. We note AusNet reference that it does not currently undertake these activities, and thus it considered these activities not to be within its base year. However, forecast opex is established on a top-down basis, and thus any rate of change uplift is inherently also based on a top-down rather than a bottom-up category level activity. **That is, this uplift is not principally for base activities, but for continued growth and adaptation of the business. We are therefore satisfied that AusNet is already provided with opex to uplift its relevant capabilities, and that including additional step change costs will risk double counting.**

However, AusNet has explained that these costs broadly relate to payments to non-network solution providers, to defer capex of $29.0 million, and for additional personnel to manage CER-related initiatives.[63] Such costs:

- appear to be associated with a fundamental transformation of the business in response to Australia's ongoing transition towards renewable energy sources and the growing uptake of CER and DER; and
- are unlikely to be provided in the trend component of opex forecasts, since the AER's output growth benchmarks are derived using a backward-looking approach that relies on historical data and that was developed in 2012.

Thus, including such costs as a step change will not result in double counting with the trend component of the AER's base-step-trend approach. Conversely, rejecting this step change means that these costs will not be counted at all.

Furthermore, these costs are associated with capex/opex substitution, which is consistent with the AER's step change framework that we describe in section 2.2.1 above.

In section 4.1 below we further discuss how the AER's opex benchmarking approach may not reflect DNSPs' forward looking costs, in light of the energy transition and the growing uptake of CER and DER.

[61] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, pp 30-31.

[62] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 19.

[63] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 18.

4. The AER's approach to benchmarking growth

In this section we discuss the benchmarking approach that the AER uses to forecast output growth, ie:

- we explain that the AER's benchmarking approach may not reflect AusNet's forward looking costs for the 2026-31 regulatory period, since it involves a backward looking approach that was first developed in 2012 and does not account for Australia's recent and ongoing energy transition; and
- we discuss two examples of precedent where other regulators have applied a different method for forecasting opex output growth, namely, the NZCC's decision for the fourth default price quality path for electricity distribution businesses and ESCOSA's decision for SA Water.

4.1 The AER's opex benchmarking may not reflect forward looking costs

We explain in section 2.2.2 above that the AER uses a benchmarking approach to forecast the output growth element of the trend component of opex forecasts. This involves estimating four econometric models that predict output growth based on explanatory variables that include:[64]

- customer numbers, circuit length and ratcheted maximum demand, which the AER uses to forecast output growth for each DNSP; and
- share of underground cables, an annual time trend, and dummy variables for country and DNSP, which are not used to forecast output growth.

We consider that the AER's approach:

- is unlikely to provide an accurate forecast of the increase in AusNet's opex associated with customer and network growth and the expansion of services over the 2026-31 regulatory period; and
- will not fund the step changes that the AER purports to fund.

This is because the AER's four econometric models use a backward-looking approach that relies on historical data, but the opex objectives and opex criteria refer to the recovery of forward-looking costs that may differ materially from historical observations outside of a business-as-usual environment.

The AER sets out a similar caution in the context of forecasting productivity growth, where it notes the importance of ensuring that business conditions during the historical estimation period are similar to the business conditions for the forecast period:[65]

> We agree that it is desirable to take a longer time period when estimating an underlying trend. This maximises the amount of information available to estimate an underlying productivity trend, and can help 'wash out' the effect of unusual circumstances. **However, if we use historical productivity trends to forecast productivity, we need to be confident that the historical results reflect similar business conditions to the forecast period.** (emphasis added)

The AER first consulted on its benchmarking approach in 2012 and has used this approach since its first annual benchmarking report in 2014.[66]

However, Australia's energy system and the national electricity market have changed considerably since then, such that the AER's benchmarking models are likely to have reduced explanatory power because:

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[64] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.5. Quantonomics, *Economic benchmarking results for the Australian Energy Regulator's 2024 DNSP annual benchmarking report*, 15 October 2024, pp 144-147.

[65] AER, *Forecasting productivity growth for electricity distributors*, Final decision paper, March 2019, p 35.

[66] See: AER, *Electricity distribution network service providers*, Annual benchmarking report, November 2014, pp 5, 23.

- the energy transition and the uptake of CER and DER are likely to be important drivers of DNSPs' output growth but are not captured directly in the AER's explanatory variables; and
- the overall associations between DNSPs' output growth and the AER's explanatory variables are likely to have weakened and/or rebalanced considerably and will continue to do so.

This also means that the AER's approach for forecasting output growth may be inconsistent with the October 2024 expenditure forecast assessment guideline, which requires output measures to reflect services provided to customers.[67]

We discuss these observations further in sections 4.1.1 to 4.1.2 below.

The AER can address the price reset-specific issues outlined above by accepting the step changes proposed by AusNet.

However, over the longer term, the AER may need to revise or replace its base-step-trend approach in response to the change in business conditions associated with the ongoing transition towards renewable energy sources and the growing uptake of CER and DER. The New Zealand Commerce Commission (NZCC) acknowledged this issue in its November 2024 decision setting out the fourth default price quality path for electricity distribution businesses in New Zealand.[68]

Three potential options that the AER can adopt to improve the accuracy of its output growth forecasts over the longer term are:

- modifying its econometric model specifications to include different explanatory variables that capture the key drivers of future output growth, eg, the AER's export services network performance report includes the proportion of customers using export services and the proportion of energy delivered by exports, although we note that this retains a backward-looking approach;
- adopting different econometric models such as those previously proposed by the New South Wales DNSPs for the 2014-19 regulatory period, eg, fixed effects and random effects panel data models;[69] and
- assigning less weight to the outputs of its econometric benchmarking models and taking more consideration of the operating environment for each DNSP.

One example of the first point above is the New Zealand Commerce Commission's (NZCC) approach that includes capex average growth rate as an explanatory variable when forecasting non-network opex growth for electricity distribution businesses.

In that decision, the NZCC also considered the second point above but did not implement it after concluding that the inclusion of 'fixed effects' did not improve the fit of its output growth model.

The Essential Services Commission of South Australia's (ESCOSA) approach for SA Water provides an example of the third point above, whereby ESCOSA calculated SA Water's opex allowance by including forecast output growth as a step change.

We discuss these two examples in section 4.2 below.

[67] AER, *Expenditure forecast assessment guideline for electricity distribution*, October 2024, pp 23-24.

[68] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, para C27.

[69] See, for example: AER, *Ausgrid distribution determination 2015-16 to 2018-19, Attachment 7 – Operating expenditure*, Final decision, April 2015, table A.4.

4.1.1 The AER does not account for the energy transition and the uptake of CER and DER

The business conditions that prevailed at the time the AER developed its benchmarking approach for DNSPs, ie, 2012 to 2014, are unlikely to reflect the business conditions that will apply for AusNet's 2026-31 regulatory period due to factors such as:

- Australia's recent and ongoing transition towards renewable energy sources; and
- the growing uptake of consumer energy resources (CER) and distributed energy resources (DER).

Such factors are leading to a more complex energy system with more significant daily variations in two-way energy flows that introduce new opex cost drivers, such as:

- higher expenditure on low voltage network management and planning;
- higher costs to manage larger amounts of network data;
- higher emergency costs in response to climate change; and
- higher costs for implementing regulatory reforms to integrate CER into the energy system.

Consequently, these recent developments mean that DNSPs must increase their network capex and opex materially to meet the expected growth in electricity demand and to maintain the quality, reliability and security of supply of standard control services.

However, the models that the AER uses for forecasting output growth do not take these factors into account, such that:

- the explanatory variables that the AER currently uses may not adequately capture the key drivers of output growth and thus may have low explanatory and predictive power on future output growth; and
- the AER's models may omit important drivers of future output growth such as those discussed above, in which case:
  - the coefficients observed from the models may be biased; and
  - the models may generate inaccurate forecasts of future output growth.

Thus, if the AER continues to use the 2012 models to forecast output growth, then it is likely that its forecasts will:

- incorrectly estimate the opex that DNSPs require to meet the opex objectives; and
- be inconsistent with the October 2024 expenditure forecast assessment guideline, which requires output measures to reflect services provided to customers.

Such opex forecasting errors are likely to be more pronounced for DNSPs that are more impacted by Australia's energy transition and the growing uptake of CER and DER. For example, DNSPs such as AusNet that primarily serve regional and rural areas typically experience higher CER and DER uptake.[70] The AER's models are likely to underestimate the future output growth of such DNSPs more materially.

4.1.2 The explanatory power of the explanatory variables may have weakened or rebalanced

Since the time when the AER first consulted on its benchmarking approach in 2012, the explanatory power of the AER's current explanatory variables is likely to have weakened or rebalanced, in that the appropriate weights assigned across each of the explanatory variables may have changed materially.

[70] For example, 28 per cent of AusNet's customers used export services in 2023-24, which is the highest proportion observed for the five Victorian DNSPs. Exports also made up 19 per cent of all energy delivered by AusNet in 2023-24, which is also the highest proportion among the five Victorian DNSPs. See: AER, *Insights into Australia's growing two-way energy system*, Export services network performance report 2024, December 2024, table 3.1.

The AER's draft decision assigns 40.9 per cent weight to ratcheted maximum demand when forecasting AusNet's output growth, followed by customer numbers at 39.1 per cent weight and circuit length at 20.0 per cent weight.[71]

However, it is unclear whether ratcheted maximum demand remains the most important driver of output growth, given the change in energy consumption patterns since 2012, with data centre uptake becoming a key driver of energy demand.[72]

This can be seen from Baringa's observation that data centres are key drivers of forecast energy consumption for the other four Victorian DNSPs, ie:[73]

- Jemena and Powercor forecast significant increases in energy consumption over the regulatory period, driven largely by data centre uptake; and
- CitiPower and United Energy forecast energy consumption on their networks to increase initially due to CER and gas electrification and then due to data centres later in the regulatory period.

Conversely, AusNet, which has no committed connections from data centres, has the lowest growth in forecast energy consumption compared to the other four Victorian DNSPs over the 2026-31 regulatory period.[74]

While CER and gas electrification tend to contribute less to energy consumption growth compared to the corresponding contribution from data centres, the former contribute heavily to growth in required opex. For example:

- data centres tend to have stable energy demand, while CER and DER exhibit daily variations in two-way energy flows that require more voltage regulation, more frequent maintenance, and more extensive forecasting and planning; and
- data centres tend to be located in or near population centres, while CER and DER can be located in dispersed locations that may be far from population centres, which increases the costs of monitoring inverter compliance, as well as increasing customer support costs and the costs of operational responses to minimum system load events.

Consequently, the high weight that the AER assigns to ratcheted maximum demand may not be sufficiently granular for forecasting output growth for the 2026-31 regulatory period, such that the weights assigned across each of the AER's explanatory variables may need to be rebalanced.

It follows that AusNet's lower growth in forecast energy demand compared to the other four Victorian DNSPs does not necessarily translate to a lower growth in AusNet's required opex over the 2026-31 regulatory period.

Instead, the appropriate weights that should be assigned to each of the AER's explanatory variables when forecasting AusNet's output growth for 2026-31 are likely to be materially different compared to those derived from the AER's backward-looking approach that was developed in 2012.

Furthermore, AusNet may have to incur higher opex to maintain network resilience as a service to its customers, but this variation in costs will not be captured in the three explanatory variables that the AER

[71] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.5.

[72] See: AEMO, https://www.aemo.com.au/newsroom/news-updates/aemos-updated-forecasting-methodology-targets-rapidly-growing-electricity-loads, accessed 18 November 2025.

[73] Baringa, *Distribution demand forecast assessment: Review of AusNet Services' 2026-31 regulatory proposal*, Final report, July 2025, pp 7, 23.

[74] Baringa, *Distribution demand forecast assessment: Review of AusNet Services' 2026-31 regulatory proposal*, Final report, July 2025, pp 7, 23.

currently uses to forecast output growth for each DNSP. Thus, the AER will also need to consider adding additional explanatory variables that capture the opex drivers associated with the energy transition.

4.2 Methods applied by other regulators

In sections 4.2.1 to 4.2.2 below we discuss two examples of precedent where other regulators have applied a different method for forecasting opex output growth, namely:

- the NZCC's decision for the fourth default price quality path for electricity distribution businesses; and
- ESCOSA's decision for SA Water.

4.2.1 NZCC includes capex average growth rate when forecasting output growth

The NZCC published its final decision in November 2024 setting out the fourth default price quality path for electricity distribution businesses in New Zealand.

In that decision, the NZCC used a flexible approach to assessing step changes and adopted a zero productivity factor, noting the fast changing and more uncertain environment for consumers and distribution networks over the fourth default price quality path period:[75]

> C27 A theme in EDB submissions on the DPP4 Issues paper was a call to either **revise or replace the base, step, and trend approach to deal with a faster-changing and more uncertain environment for consumers and distribution networks over DPP4**.
>
> C28 Aurora noted the scale of change, but reinforced the uncertainties involved:
>
> > The pace and scale of change during the DPP4 regulatory period is uncertain. The Commission has an important role to play in managing this uncertainty; capex allowances need to be appropriate to support growth and opex allowances need to include sufficient step changes so distributors can meet the changing demands of consumers and stakeholders.
>
> C29 **Opex allowances of themselves cannot manage uncertainty. However, the uncertainty Aurora highlights has informed our decision for a more flexible approach to assessing step changes (given that allowing some step change is a least-regrets option) and the balance of factors that led to our decision of a 0% productivity factor.** (emphasis added)

The NZCC calculated two separate opex scale trends for network opex growth and non-network opex growth, namely:[76]

- percentage change in network opex growth per annum is calculated as:

  $0.44 \times \%\ change\ in\ connection\ points + 0.53 \times \%\ change\ in\ line\ length$; and

- percentage change in non-network opex growth per annum is calculated as:

$$0.20 \times \%\ change\ in\ connection\ points + 0.35 \times \%\ change\ in\ line\ length + 0.31 \times \%\ change\ in\ capex.$$

The inclusion of a capex term for forecasting non-network opex growth departs from the approach that the NZCC previously applied in its third default price quality path. That approach involved forecasting non-

[75] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, paras C27-C29.

[76] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, para C257, table C9.

network opex growth using connection points and line length, such that the same econometric functional form applied to network opex growth and non-network opex growth.[77]

The NZCC also considered other explanatory variables as part of its decision, including:[78]

- annual energy delivered (MWh);
- maximum coincident peak demand (MW);
- ratcheted (cumulative annual maximum) coincident peak demand (MW) and energy delivered (MWh);
- a 'time' variable (year);
- regulatory asset base ($000); and
- fixed effects for EDBs.

However, the NZCC decided on its final approach after assessing the statistical significance of each explanatory variable and how its inclusion affected model fit.[79]

The NZCC assessed that including a capex term:[80]

- did not improve its network opex models; and
- improved its non-network opex models.

The NZCC also considered that the statistically significant positive correlation that it observed between non-network opex and capex made plausible sense from economic and business operation perspectives.[81]

Thus, the NZCC decided to include a capex variable for forecasting non-network opex growth, but did not do so for network opex growth.[82]

4.2.2 ESCOSA included a step change for forecast output growth in SA Water's opex allowance

ESCOSA published its final regulatory determination in June 2024 regarding SA Water's maximum revenues for the period from 1 July 2024 to 30 June 2028.

SA Water's proposal for that regulatory process did not include an explicit opex amount for output growth. However, SA Water proposed opex growth listed by project and included this additional expenditure as step changes. Consistent with SA Water's proposal, ESCOSA's draft determination did not provide an allowance for customer growth.[83]

Several stakeholder submissions to the draft determination queried whether ESCOSA had included sufficient expenditure to accommodate growth.[84]

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[77] NZCC, *Default price-quality paths for electricity distribution businesses from 1 April 2025 – Final decision*, Reasons paper, 20 November 2024, paras 2.110-2.111.

[78] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, paras C312-C314.

[79] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, paras C320-C377.

[80] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, paras C336-345.

[81] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, para C346.

[82] NZCC, *Electricity distribution services default price-quality path determination 2025, Attachment C Operational expenditure*, [2024] NZCC 28, 20 November 2024, para C348.

[83] ESCOSA, *SA Water regulatory determination 2024*, Final determination: Statement of reasons, June 2024, pp 232-233.

[84] ESCOSA, *SA Water regulatory determination 2024*, Final determination: Statement of reasons, June 2024, p 232.

ESCOSA considered that there were limitations to inflating opex by expected output growth, and decided to apply a more targeted approach.[85]

Consequently, ESCOSA provided $4.8 million of additional opex to accommodate 'natural' growth for the regulatory period, ie, the necessary growth of expenditure to handle increased customer numbers, in addition to growth expenditure included under step change projects. ESCOSA calculated this amount by:[86]

- observing that its determination for the previous period accepted SA Water's proposed $4.2 million opex for natural growth; and
- adjusting for forecasts of customer connections for the 2024-28 period.

However, ESCOSA notes that its position on the opex associated with natural growth was adopted for the 2024-28 period only and should not be assumed to apply in future regulatory periods.[87]

[85] ESCOSA, *SA Water regulatory determination 2024*, Final determination: Statement of reasons, June 2024, p 234.

[86] ESCOSA, *SA Water regulatory determination 2024*, Final determination: Statement of reasons, June 2024, p 234.

[87] ESCOSA, *SA Water regulatory determination 2024*, Final determination: Statement of reasons, June 2024, p 234.

A1. AER's draft decision on AusNet's total opex for 2026-31

AusNet proposed 11 opex step changes totalling $131.7 million, which makes up 7.7 per cent of its proposed total opex forecast.[88] In table 4.1 below we summarise the AER's assessment of AusNet's 11 proposed step changes.

Table 4.1: AER's assessment of AusNet's proposed step changes ($ millions)

Step change	AusNet's proposal	AER's estimate	Difference	AER's views
Flexible services and non-network solutions	8.5	-	-8.5	• Insufficient information to justify proposed investments or that the programs overall represent prudent or efficient investments. • Insufficient information to demonstrate that the relevant services will be available or procured, including the proposed amount reflects the efficient amount required. • Ambiguity regarding AEMO data exchange costs as an anticipated future compliance requirement. • Costs for dynamic management capabilities are already provided through the rate of change factor in the base-step-trend forecasting approach.
ESV more frequent pole inspections	8.0	-	-8.0	• The costs associated with ESV's direction to increase scheduled pole inspection frequency from every six years to every five years are immaterial and are covered by the trend factor in the overall opex estimate. • AusNet's base year does not account for cost savings from the previous decrease in inspection frequency in 2019, such that including this step change will result in EBSS rewards.
Fleet electrification	-0.7	-0.7	-0.0	• This proposed opex / capex trade-off is prudent and efficient, although AusNet will need to update the values to account for the AER's fleet assessment.
Digital (SaaS, licences)	39.9	13.3	-26.7	• AusNet has not included the required economic analysis demonstrating the prudence and efficiency of the proposed total expenditure. • Some subprograms of the digital step change generate opex benefits that exceed the costs and thus no incremental expenditure is required. • AusNet's $23.8 million of SaaS implementation and customisation costs for its customer engagement program was incorrectly identified as capex instead of opex, but the information was received too late and should be corrected in the revised proposal.
Early fault detection rollout	7.8	-	-7.8	• The costs of the project should not be borne by consumers since AusNet has not sufficiently justified the benefits of the project or signalled a new regulatory obligation.
Digital efficiencies	-3.9	-	3.9	• Placeholder of zero, pending AusNet's revised proposal with an updated step change that adjusts for changes in the estimate for the digital step change above.
Preparedness and response	9.2	-	-9.2	• AusNet's activities are likely prudent but the relatively small step up in proposed costs can be managed by the business without a step change.

[88] AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, p 16.

Step change	AusNet's proposal	AER's estimate	Difference	AER's views
				• The step change is relatively immaterial, ie, less than one per cent, and is accounted under the trend component relating to improvements in a business's operations. • Providing additional incremental opex for minor changes in specific costs risks double counting and encourages numerous small step changes in opex proposals.
Resilience (hazard tree program)	15.0	-	-15.0	• AusNet has not provided sufficient detail on avoided capex to justify including this step change as a capex-to-opex trade off. • Unclear whether there is a strong relationship between hazard tree reduction and network hardening, and the cost-benefit analysis is not sufficiently robust to depict a net benefit to consumers accurately.
CRM and communications	15.7	-	-15.7	• The proposal appears to be a discretionary expansion of existing business as usual activities, and AusNet has not justified how these types of activities meet the step change criteria. • The forecast increase is relatively immaterial and thus is captured in the base year opex and trend components of total forecast opex.
Emergency backstop mechanism	21.6	5.4	-16.3	• The AER previously approved a cost pass through for the emergency backstop mechanism in 2024, and these costs are included in the final year increment for AusNet. • The AER's reduced $5.4 million step change reflects the allocation of distributed energy resource management systems licence fees to emergency backstop mechanism activities, ensuring that AusNet only recoups the additional costs arising in the regulatory control period without double counting.
Insurance	10.5	-	-10.5	• Increasing insurance costs will be captured through the price growth component of trend, which includes an allowance for increases in non-labour price growth, such that premium increases that exceed CPI will be offset by other non-labour costs rising by less than CPI. • The increasing insurance costs are immaterial at 0.6 per cent of total forecast opex.
Negative step change insurance	-	-58.1	-58.1	• The AER applied a negative step change to remove the expected overforecasting of insurance premiums, whereby the distribution determination for the previous period included additional insurance allowances that AusNet ended up underspending due to changes in market conditions. • AusNet's underspend translates to 2.5 per cent of total actual or estimated opex for the 2026-31 regulatory period.
Total step changes	**131.7**	**-40.2**	**-171.9**	

Source: AER, AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031, Attachment 3 – Operating expenditure, Draft decision, September 2025, table 3.1, pp 16-34. AER note: Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

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