Victorian DNSP insurance premiums

Report for DLA Piper on behalf of Jemena, AusNet, Powercor and United Energy

27 November 2025

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Disclaimer

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Executive summary

In its draft decisions for AusNet Electricity Services Pty Ltd (AusNet), Jemena Electricity Networks (Vic) Ltd (Jemena), Powercor Australia Ltd (Powercor) and United Energy Distribution Pty Ltd (United Energy) (together, the Victorian DNSPs), the Australian Energy Regulator (AER) included a base year non-recurring efficiency gain in its alternative operating expenditure (opex) estimate, together with a negative step change, both relating to the insurance premiums. The AER explains that these adjustments are the result of a material difference between the implicit allowances (inclusive of the approved step change) for insurance premiums in the current 2021-26 regulatory control period and actual insurance premiums in that period.

DLA Piper has engaged me to prepare an independent expert report in respect of the AER's draft decisions on:

1. the approach the AER is purporting to have taken to determining the Victorian DNSPs' insurance opex in the draft decisions, including:
   i. the AER's reasoning and rationale for its purported approach; and
   ii. the AER's stated objectives for its purported approach;
2. the approach the AER has actually taken to determining the Victorian DNSPs' insurance opex in the draft decisions, including:
   i. whether the AER's actual approach is consistent with its purported approach as identified by me in response to 1; and
   ii. to the extent the AER's actual approach is inconsistent with its purported approach, whether the AER's approach nonetheless is consistent with the AER's rationale, and achieves the AER's objectives, identified by me in response to 1(i) and (ii);
3. the merits of the AER's reasoning, rationale and objectives as stated in the draft decisions and identified by me in response to 1.

Regulatory framework for the opex allowances and the EBSS

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

The AER must accept a distribution network service provider's (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:

- 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 require the AER to evaluate the prudency and efficiency of a DNSP's opex forecast in totality. Importantly, 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 opex factors as part of its decision. These factors include (among other things):[1]

- the AER's most recent annual benchmarking report;

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

- the actual and expected opex of the DNSP during any preceding regulatory control periods; and
- whether the opex forecast is consistent with any incentive scheme or schemes that apply to the DNSP.

The AER prefers a 'base-step-trend' approach to assessing forecast opex for a regulatory control period for most opex categories, which:

- starts with DNSP's actual opex in a base year (**base**) of the preceding regulatory control period, adjusted for the difference between efficient opex and actual base year opex;
- applies an annual rate of change (**trend**) in forecast opex that accounts for the difference between forecast final year and base year opex, and changes in real prices, output growth and productivity in the regulatory control period; and
- adds step changes (**step**) that account for any other efficient opex not captured in the base opex or the rate of change.

The AER also applies an efficiency benefit sharing scheme (EBSS) which provides a fair sharing between the DNSP and users of efficiency gains and efficiency losses in a regulatory control period, which are defined as the amount by which the DNSP's total actual is less than and exceeds (respectively) forecast opex accepted or substituted by the AER in its distribution determination for that period.

Where applied to a DNSP, the EBSS has the following effects:

- gains and losses arising from a temporary change in opex relative to the forecast are retained by the DNSP for a period of six years before the benefits or costs of the temporary underspend or overspend is passed through to customers, ie, a one-off reduction in opex of $100 in year 1 is passed through to customers in year 7 by way of a negative $100 EBSS carryover amount in that year;
- gains and losses arising from a permanent increase or decrease in opex relative to forecast opex are retained by the DNSP for a period of six years, before those gains and losses are passed through to customers, ie, a permanent reduction in opex of $100 per annum in year 1 is retained by the DNSP in each year until year 7, when the opex savings are passed through to customers by way of a permanent reduction in the effective revenue allowance for opex (comprised of the collective effect of the opex allowance and the EBSS carryover amounts) of $100 per annum; and
- the rewards and penalties of any gains or losses is invariant as to the timing within a regulatory control period of the occurrence of those gains/losses.

Interpreting the AER's 2026-31 draft decisions

In the 2021-26 final decisions, the AER accepted that forecast insurance premiums for the Victorian DNSPs would be materially higher than in the previous regulatory control period. The AER noted that the information provided by these DNSPs' insurance brokers (Aon and Marsh) in relation to expected insurance premium price increases over the 2021-26 regulatory control period was consistent with opinions from its expert consultant, Taylor Fry. The then prevailing market conditions that led to such forecast increases in insurance premiums were mainly driven by international bushfire claims.

At the time, the AER considered using either cost pass throughs or step changes to implement the opex adjustment, and decided that step changes were more appropriate, acknowledging the uncertainty of the forecasts of the insurance premiums. By addressing forecast increases of insurance premiums as step changes, incentives remained with the businesses to actively work to moderate the expected increases in insurance premiums.

Notwithstanding its previous decision that the Victorian DNSPs' insurance premiums in the 2021-26 regulatory control period would be subject to the regular opex incentives, the draft decisions make the following three adjustments specifically related to the DNSPs' insurance costs in that period:

- a non-recurrent efficiency gain adjustment was included in the EBSS models of the Victorian DNSPs, which resulted in a negative EBSS carryover amount being included in each year of the 2026-31 regulatory control period;
- a corresponding non-recurrent efficiency gain adjustment was made to base year opex in the opex models of the Victorian DNSPs, which resulted in an increase to the DNSPs' opex allowances in each year of the 2026-31 regulatory control period; and
- a negative step change adjustment was made that decreases the DNSPs' opex allowances in each year of the 2026-31 regulatory control period.

The AER performed the above three steps with the stated aim of:

- setting a forecast opex allowance equal to that required by a prudent operator;
- ensuring that the adjustment to the opex allowance for the difference between the final year and the base year does not result in an implicit insurance premium allowance that is 'materially higher than that required by a prudent operator'; and
- returning all the 2021–26 insurance premium outperformance to customers, in a manner consistent with all insurance underspends over the 2021-26 regulatory control period being non-recurrent efficiency gains, noting that:

> …[the NSP] retains its share of the insurance premiums underspend as it retains the time value of holding the underspends for 6 years.

In section 3.3, I calculate the total changes in insurance revenue allowances for the 2026-31 regulatory control period for each of the Victorian DNSPs resulting from the adjustments effected by the AER's draft decision. These are also summarised in Table E-1 below.

Table E-1: Summary of changes in insurance revenue allowances for the 2026-31 regulatory control period for each of the Victorian DNSPs by AER's adjustments

Step	$m 2025-26	Jemena	AusNet	Powercor	United Energy
Two	Non-recurrent efficiency gains (trended)	[redacted]	[redacted]	[redacted]	[redacted]
Three	Differences between final and base year (insurance components - trended)	[redacted]	[redacted]	[redacted]	[redacted]
Four	Insurance step change	[redacted]	[redacted]	[redacted]	[redacted]
Five	Revenue adjustment in PTRM (from EBSS)	[redacted]	[redacted]	[redacted]	[redacted]
	Total change	[redacted]	[redacted]	[redacted]	[redacted]

Insofar as the Victorian DNSPs' base year insurance costs (trended) provide a reasonable indication of their expected insurance costs in the 2026-31 regulatory control period, these AER adjustments will result in the DNSPs' opex allowances for the period being insufficient to compensate them for their efficient costs of providing standard control services.

This is evident from the following table, which discloses the total insurance opex allowances, and the revenue allowances for insurance opex net of the EBSS carryover adjustments, for each of the Victorian DNSPs.

Table E-2: Summary of insurance revenue allowances for the 2026-31 regulatory control period for each of the Victorian DNSPs

$m 2025-26	Jemena	AusNet	Powercor	United Energy
Insurance cost embedded in base year actual opex (step one)	[redacted]	[redacted]	[redacted]	[redacted]
Net change for insurance allowance in opex (step two to four)	[redacted]	[redacted]	[redacted]	[redacted]
Insurance allowances in opex	[redacted]	[redacted]	[redacted]	[redacted]
Revenue adjustment in PTRM (from EBSS) (step five)	[redacted]	[redacted]	[redacted]	[redacted]
Net insurance allowances in revenue	[redacted]	[redacted]	[redacted]	[redacted]

Insurance underspend was likely impacted by efficient cost management

The AER's draft decisions conclude that the insurance premium underspends in each regulatory year of the 2021-26 regulatory control period by the Victorian DNSPs were non-recurrent efficiency gains. This conclusion implicitly attributes the lower than expected insurance premiums to external factors outside of the control of the businesses and not, in whole or in part, to management efforts to efficiently manage their insurance premiums, and in particular their bushfire insurance premiums.

The Victorian DNSPs mitigated their insurance costs over the 2021-26 regulatory control period by employing a range of measures including:

- changing the coverage limits for their bushfire liability, that occurred following detailed risk modelling;
- effective engagement with the insurance market to increase the level of competition (and the size of the market) by seeking insurers in new markets such as China and Singapore, more effectively engaging with existing insurers, and the increased use of a captive insurer strategy;
- investing in new technology that reduced the chance and/or severity of bushfire damage caused by networks, including installing Rapid Earth Fault Current Limiters and early fault detection systems;
- increased and/or more effective vegetation management programs; and
- improve asset inspection and maintenance activities.

The AER's draft decisions ignore the expenditure incurred and management effort invested by the Victorian DNSPs to contain their insurance premium increases over the 2021-26 regulatory control period. The failure to recognise and reward the DNSPs' expenditure and management efforts undermines ex-ante regulatory incentives, and encourages businesses to do nothing to mitigate cost increases, by introducing the risk that these efforts will be clawed back through revenue allowances in subsequent regulatory determinations.

Implication of the draft decisions

The opex and EBSS adjustments are inconsistent with their intended purpose

The AER's draft decisions made three adjustments related to DNSP insurance costs, ie:

- a non-recurrent efficiency gain adjustment was included in the EBSS, which resulted in negative EBSS carryover amount being included in each year of the 2026-31 regulatory control period;
- a corresponding non-recurrent efficiency gain adjustment was made to base year opex in the opex models of the Victorian DNSPs, which resulted in an increase to the DNSPs' opex allowances in each year of the 2026-31 regulatory control period; and

- a negative step change adjustment was made that decreases the DNSPs' opex allowances in each year of the 2026-31 regulatory control period.

However, the AER's use of these adjustments is inconsistent with the stated reasons for introducing these adjustments into the EBSS and opex model, specifically:

- base year opex does not include a temporary saving (non-recurrent efficiency gain) in insurance costs, which is not expected to be sustained over the 2026-31 regulatory control period; and
- there is no expectation of a step down in insurance costs (ie, substantially lower costs) over the 2026-31 regulatory control period compared to the base year.

Instead, the effect of these adjustments is to undermine the incentive framework and impose significant penalties on the Victorian DNSPs, in a bid to clawback gains associated with previous management efficiency gains and lower than forecast insurance premiums.

The use of ex post adjustments for ex ante forecast inaccuracies undermine the incentive regime

The AER's reasons for applying a non-recurrent efficiency gain adjustment and negative insurance step change in the draft decisions suggest that it is seeking to make a retrospective adjustment for over estimating insurance premium increases in the 2021-26 regulatory control period. However, the forecast opex and EBSS provisions in the NER do not provide for 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.

Neither clause states that the AER should, or has the discretion to, adjust its opex forecast with the effect of making retrospective adjustments that recoup from the Victorian DNSPs, or penalise the DNSPs for benefiting from, actual opex not increasing as expected. The ex post clawback of underspends on insurance premiums in the 2021-26 regulatory control period is inconsistent with the AER's ex ante regulatory framework.

Further, the draft decision is inconsistent with its 2021 decisions for the Victorian DNSPs, where it understood that there was uncertainty in its insurance cost forecasts:[2]

> On balance, we are of the view that in the current circumstances, while there is some uncertainty associated with forecasting insurance premium increases, we can use the forecasts of future insurance premium increases to include a step change in our alternative estimate.

Notwithstanding this uncertainty, the AER explicitly stated, in its decisions for the 2021-26 regulatory control period, that the regulatory incentives would apply to the insurance step change:[3]

> … we consider on balance, that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.

In other words, despite the uncertainty of future insurance premiums, the AER affirmed in its 2021 decisions for the Victorian DNSPs that:

- the incentive regime would apply to insurance costs; and
- the Victorian DNSPs would, therefore, be:

[2] AER, *Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 6-36.

[3] AER, *Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 6-37.

> rewarded if their operating costs were lower than the implicit allowance; and
> penalised if their operating costs were higher than forecast.

The AER rejected the nomination of insurance premiums as a cost pass through event

While the forecast opex and EBSS provisions in the NER do not allow the AER to impose retrospective adjustments for past outperformance, the NER does allow the AER to claw back past losses or gains when a pre-defined event that materially increases or decreases a DNSP's capex or opex occurs within a regulatory control period.

Specifically, clause 6.5.10 of the NER allows DNSPs to nominate unanticipated changes in insurance premiums as a cost pass through event in their regulatory proposal and, where the AER accepts such an event in the DNSP's distribution determination for the regulatory control period, the cost pass through arrangements set out in clause 6.6.1 allow the DNSP to cover the costs incurred as a result of such an event occurring in the regulatory control period. Jemena and AusNet, in their 2020 regulatory proposals, included insurance premiums as a proposed cost pass through event, however, this proposal was rejected by the AER. While Powercor and United Energy in their revised regulatory proposals included insurance premiums as a nominated insurance premiums pass through event, this was also rejected by the AER.

In effect, the AER's draft decisions to claw back the insurance premiums underspends in the 2021-26 regulatory control period reflects a circumventing of the NER, by applying a mechanism that the AER is precluded from applying in the present circumstances.

AER's intended adjustment does not allow for reasonable cost recovery

The draft decisions, which have the effect of clawing back past gains from insurance costs increases being less than forecast, introduce an asymmetric risk that means the Victorian DNSPs do not have a reasonable opportunity to recover their efficient costs. This asymmetry arises because the AER has only reclassified, on an ex post basis, insurance cost outperformance as temporary, without articulating a general principle as to when there are material differences between forecast and actual costs will be reclassified as temporary.

I note that there are number of examples over the 2021-26 regulatory control period where actual costs were materially higher than forecast over that period. These inaccurate forecasts have not been examined by the AER to assess whether they should be reclassified as temporary in nature. Note that any ex post assessment would necessitate the difficult task of determining whether the difference between forecast and actual costs was due to efficiency/inefficiency of the DNSP or was caused by factors beyond the control of the DNSP (ie, due external factors or random events).

A regulatory framework that provides for the retrospective lowering of the rewards for outperformance but does not provide for retrospectively lowering the penalties for underperformance introduces a downward bias in outcomes and, consequently, does not provide DNSPs with a reasonable opportunity to recover their efficient costs.

That said, there are strong economic reasons why regulators do not seek to assess the efficiency of past expenditure, primarily because regulators cannot directly observe what constitutes efficient behaviour. In my opinion, this is one of the main reasons why regulators apply an ex ante regulatory framework.

The draft decisions undermine the total opex regime

The NER require DNSPs to propose the total forecast opex required to achieve five opex objectives for the regulatory control period. 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.

In other words, the regulatory framework requires the assessment of total forecast opex for the forthcoming regulatory control period, rather than forecasts of subcomponents of opex such as individual projects or programs. This tacitly accepts that there is significant uncertainty in forecasting costs for individual opex subcomponent and, while the costs for some opex subcomponents may be higher than forecast, others will be lower than forecast. It is then up to the DNSP to prioritise its expenditure within the approved total opex allowance.

The provision of a total opex allowance that the DNSP must spend within underpins the incentive properties of the regulatory regime, with the AEMC stating, in making its 2012 rule change for the economic regulation of network service providers:

> The level, rather than the specific contents, of the approved expenditure allowances underpin the incentive properties of the regulatory regime in the NEM. That is, once a level of expenditure is set, it is locked in for a period of time, and it is up to the NSP to carry out its functions as it sees fit, subject to any service standards.

The draft decisions, which effectively establish an insurance cost subcomponent allowance:

- ignore the uncertainty of forecasting individual opex subcomponents and that DNSPs will outperform on some opex subcomponents and underperform on others but must manage their overall opex within their budget; and
- diminish the incentives the Victorian DNSPs have to efficiently reduce costs, given that costs are interrelated, for example, the impact of bushfires can be prudently addressed by the DNSPs in a number of ways including insurance, effective vegetation management, investments in Rapid Earth Fault Current Limiters (REFCLs), or the increased replacement of wooden poles.

However, instituting an insurance opex subcomponent will mean that a DNSP will be hesitant to manage its bushfire risks by reducing its bushfire insurance costs while investing in other mitigation measures, even when it is efficient to do so.

The draft decisions do not provide a fair sharing of temporary efficiency gains

In the draft decisions for the Victorian DNSPs, the AER described its adjustments as providing a fair sharing of efficiency gains, by treating insurance premium outperformance in each regulatory year of the 2021-26 regulatory control period as temporary efficiency gains. Under the current EBSS, temporary efficiency gains are retained by a DNSP for a period of six years, before being returned to customers.

A summary of our analysis of the financial impacts of the draft decisions is set out below in Table E-3.

Table E-3: Summary of net impact of AER draft decisions on revenue allowances for insurance for each of the Victorian DNSPs

$m 2025-26	Jemena	AusNet	Powercor	United Energy
NPV of insurance opex underspends in 2021-26	[redacted]	[redacted]	[redacted]	[redacted]
Expected NPV reward for temporary gains under EBSS	[redacted]	[redacted]	[redacted]	[redacted]
Estimated NPV reward/penalty for temporary gains provided by draft decisions	[redacted]	[redacted]	[redacted]	[redacted]
Difference to expected NPV reward for temporary gains under EBSS	[redacted]	[redacted]	[redacted]	[redacted]

Source: Jemena, AusNet, Powercor and United Energy; AER draft decisions, and HoustonKemp analysis of AER draft decision.

Table E-3, shows that the financial impacts of the draft decisions are inconsistent with the AER's stated objective of treating insurance outperformance in each regulatory year of the 2021-26 regulatory control period as a temporary efficiency gain. In particular, the insurance revenue outcomes of the draft decisions are not consistent with the application of the EBSS applicable to the Victorian DNSPs in the 2021-26 regulatory control period where, consistent with the AER's stated intention, the DNSPs' insurance underspends in each regulatory year of the period are treated as non-recurrent, or temporary, rather than perpetual, efficiency gains. Instead, Table E-3 highlights that the insurance revenue outcomes of the draft decisions for Jemena, Powercor and United Energy represent not simply a “claw back” of the over-forecasting of insurance opex in the 2021-26 final decisions, but an ex post punishment of their underspends of those forecasts.

1. Introduction

In its draft decisions for AusNet Electricity Services Pty Ltd (AusNet), Jemena Electricity Networks (Vic) Ltd (Jemena), Powercor Australia Ltd (Powercor) and United Energy Distribution Pty Ltd (United Energy) (together, the Victorian DNSPs) the Australian Energy Regulator (AER) included a base year non-recurring efficiency gain in its alternative operating expenditure (opex) estimate, together with a negative step change, both relating to insurance premiums. The AER explains that these adjustments are the result of a material difference between the implicit allowances (inclusive of the approved step change) for insurance premiums in the current 2021-26 regulatory control period and actual insurance premiums in that period.[4]

DLA Piper has engaged me to prepare an independent expert report in respect of the AER's draft decisions on:

1. the approach the AER is purporting to have taken to determining the Victorian DNSPs' insurance opex in the draft decisions, including:
   i. the AER's reasoning and rationale for its purported approach; and
   ii. the AER's stated objectives for its purported approach;
2. the approach the AER has actually taken to determining the Victorian DNSPs' insurance opex in the draft decisions, including:
   i. whether the AER's actual approach is consistent with its purported approach as identified by me in response to 1; and
   ii. to the extent the AER's actual approach is inconsistent with its purported approach, whether the AER's approach nonetheless is consistent with the AER's rationale, and achieves the AER's objectives, identified by me in response to 1(i) and (ii);
3. the merits of the AER's reasoning, rationale and objectives as stated in the draft decisions and identified by me in response to 1.

I attach a copy of the letter of engagement as Annexure A.

1.1 Experience and qualifications

I set out my academic qualifications, training and experience below.

Training and experience

I have more than 20 years' experience working as a consulting economist in Australia. In this time, I have accumulated substantial experience in financial analysis, particularly in relation to economic regulation and contract arbitrations. I have developed this expertise in the course of advising corporations, regulators and governments in Australia and the Asia-Pacific region on a wide range of competition, regulatory and financial economics assignments.

My industry sector experience spans energy and gas, aviation, maritime ports, rail, telecommunications, water, public lighting, and wholesale ethanol.

[4] AER, *Jemena Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, AER, *AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, AER, *Powercor Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025, and AER, *United Energy Services electricity distribution determination 1 July 2026 – 30 June 2031*, Attachment 3 – Operating expenditure, Draft decision, September 2025. (collectively referred to as the draft decisions).

I have deep experience in relation to both the development and application of the National Electricity Rules (NER) as they apply to incentive schemes applying to the distribution network businesses, including the Efficiency Benefit Sharing Scheme (EBSS) and the setting of expenditure allowances. In particular:

- I advised Energy Networks Australia on the strategic issues likely to arise from the 2022 review of the AER's incentive schemes. This included calculation of the benefits that have been realised under the current incentive schemes to date, which involved a quantitative assessment of EBSS outcomes for all distribution networks in the NEM;
- in 2022, I assisted the Independent Pricing and Regulatory Tribunal on the incentive mechanisms to be applied in the new water pricing regulatory framework. I also assisted the Tribunal in developing the expenditure incentive mechanisms included in its final decision for the Sydney Desalination plant;
- I was a senior member of a HoustonKemp team that produced a number of due diligence reports for both buyers and sellers that focused on explaining the regulatory framework, including the operation of the incentive schemes, for electricity distribution businesses. Recent reports were developed in relation to the sale of Spark Infrastructure Group (2021), Ausgrid (2021), and AusNet (2021);
- in 2020, I authored an expert report on incentive implications of either applying, or not applying, the EBSS to Jemena's operating expenditure performance for the period commencing on 1 July 2021 through to 30 June 2026. This report was submitted to the AER in the context of its draft decision for Jemena's Victorian electricity distribution network;
- in 2017, I advised ActewAGL Distribution on potential strategies for the remittal of its operating expenditure allowance for the 2014-19 period. This assistance included modelling the financial implications of different strategies, potential implications for the 2019 revenue reset, the interaction with the AER's EBSS, and the implications of adverse capital expenditure and service quality outcomes;
- in 2017, I advised Endeavour Energy on its operating expenditure allowance proposal for its 2019-24 regulatory reset;
- in 2016, I provided a submission to the Australian Competition Tribunal on the application of the EBSS on behalf of the Victorian distribution networks;
- in 2015, I provided an expert report for ActewAGL Distribution's gas distribution business, responding to the AER's draft decision on the EBSS carry forward amounts to be included in the revenues for 2016/17 to 2020/21 period; and
- in 2014, I advised Ausgrid on the estimation of the efficiency carry-forward to be applied in the 2014-19 period. This advice extended to strategic advice on the implications of the AER's Better Regulation new EBSS.

My analysis has been included in my reports submitted to regulatory bodies, such as the AER, IPART, the Queensland Competition Authority, the Essential Services Commission, and the New Zealand Commerce Commission.

Qualifications

I hold a Bachelor of Economics (high second class honours) and a Bachelor of Laws from the Australian National University. I attach a copy of my curriculum vitae as Annexure B.

1.2 Report preparation and structure

In preparing this supplementary report, my attention has again been drawn to the Federal Court of Australia Expert Evidence Practice Note (Practice Note), including the Harmonised Expert Witness Code of Conduct (the Code) and the Concurrent Expert Evidence Guidelines.[5] I acknowledge that I have read the Practice Note and agree to be bound by it. I also acknowledge, for the purpose of paragraph 4.4 of the Practice Note, that I have read the Code and that I agree to be bound by it.

[5] DLA Piper, *Letter of engagement*.

I have been assisted in the preparation of this report by my colleague Samuel Lam. Notwithstanding this assistance, the opinions in this report are my own, based wholly or substantially on specialised knowledge arising from my training, study or experience, and I take full responsibility for them.

I 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, and the Efficiency Benefit Sharing Scheme (EBSS);
- section 3 assess the approach AER purports to have taken to determining the Victorian DNSPs' insurance opex in the AER's draft decisions;
- section 4 discusses that the insurance underspends were likely impacted by efficient cost management of insurance costs by the DNSPs;
- section 5 evaluates the merits of the AER's draft decisions (illustrated by reference to information on the net financial impact of the draft decision relating to insurance premiums for Powercor); and
- section 6 I provide my declaration, in accordance with the Code

Appendix A1 to this report provides two worked examples of the operation of the EBSS, one with a permanent efficiency gain and the other with a temporary efficiency gain. In Appendix A2, I provide additional information on the net financial impact of the draft decisions relating to insurance premiums for Jemena, AusNet and United Energy.

2. Regulatory framework for the opex allowances and the EBSS

This section summarises the regulatory framework for opex allowances and the EBSS. This section highlights that the opex allowance:

- reflects the costs a prudent and efficient DNSP would incur in providing regulated distribution services;
- is determined and assessed by the AER on a total expenditure basis rather than for categories of opex;
- is determined ex ante for the regulatory control period; and
- when combined with the EBSS, provides for a fair sharing between the DNSP and users for opex efficiency gains and losses.

This discussion provides background for the following sections, where I discuss:

- the AER's draft decisions adjustments to the opex allowance and EBSS relating to insurance premiums;
- the impact that DNSP management decisions had on achieving insurance premium outperformance; and
- the merits of the AER's reasoning, rationale and objectives of the draft decisions.

2.1 Opex allowance

This section summarises the regulatory framework for opex allowances, specifically:

- the requirements of Chapter 6 of NER relating to the opex allowance; and
- the AER's preferred base-step-trend approach for developing an alternative opex forecast.

The NER require 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:[6]

- meet or manage the expected demand for standard control services over that period; and
- maintain the safety of the distribution system through the supply of standard control services.

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:[7]

- 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 require 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.

[6] The other opex objectives pertain to complying with regulatory obligations, the quality, reliability, security of supply, and the achievement of emissions reduction targets. See: NER version 236, clause 6.5.6(a).

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

The AER also must have regard to 12 opex factors as part of its decision. These factors include (among other things):[8]

- the AER's most recent annual benchmarking report;
- the actual and expected opex of the DNSP during any preceding regulatory control periods; and
- whether the opex forecast is consistent with any incentive scheme or schemes that apply to the DNSP.

The AER is required to publish its proposed approach to assessing a NSP's opex and capital expenditure forecasts in its *Expenditure Forecast Assessment Guidelines*.[9] The *Expenditure Forecast Assessment Guidelines* do not bind the AER or the NSP, however, if the AER departs from the guideline it is required to state the reasons for doing so in its regulatory determination.[10]

In the *Expenditure Forecast Assessment Guideline*, the AER proposes to take a 'base-step-trend' approach to assessing opex forecasts for most opex categories.[11] This approach is consistent with the AER's stated view that:[12]

> If a DNSP operated under an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future. The ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's allowance) because DNSPs can retain a portion of cost savings made during the regulatory control period.

The base-step-trend approach can be summarised as a process consisting of the following five steps:[13]

1. As the starting point for its assessment, the AER **determines base year opex** using the NSP's actual opex in a single year, typically a recent year for which actual opex is available, removing any expenditure not estimated by this approach. The base year is generally the penultimate year of a regulatory control period (eg, typically the fourth year of a five year regulatory control period). While opex incurred for any particular opex category can vary from year to year, the AER's view is that total opex is relatively recurrent.
2. The AER will then **assess base year opex** to determine whether the opex the NSP incurred in the base year reasonably reflects the opex criteria. This assessment will begin with a comparison to outcomes from benchmarking analysis. If necessary, the AER will make an adjustment to base year opex, to ensure it reflects the opex criteria, utilising the same techniques that it may draw on to assess the efficiency of base year opex, including removing or adding non-recurring expenditure in the base year.
3. Since the opex of an efficient NSP tends to change over time due to real price and output changes, and productivity, the AER will **apply a rate of change** to an estimate of opex in the final year of the regulatory control period, in order to derive forecast opex over the forthcoming regulatory control period.

   The AER **calculates final year opex** (ie, the best estimate of opex in the final year of the regulatory control period) using the forecasts of opex accepted or substituted by the AER in making its distribution determination for the regulatory control period. That is, it takes the AER's forecast of final year opex, subtracts the difference between forecast and actual opex in the base year (adjusted as above) and then adds an amount equal to non-recurrent efficiency gains in the base year. This is equivalent to estimating final year opex by taking actual base year opex and adding the difference between forecast final year opex and forecast base year opex, before adjusting for non-recurrent efficiency gains in the base year.

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

[9] NER version 236, clause 6.4.5(a).

[10] NER version 236, clause 6.2.8(c).

[11] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution | Better Regulation*, October 2024, p 22.

[12] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution | Better Regulation*, October 2024, p 5.

[13] See, for example, AER*, Better regulation | Expenditure forecast assessment guideline for electricity distribution,* October 2024, pp 22 - 25.

4. The AER will then **add or subtract step changes** to forecast opex in each year of the regulatory control period to account for any forecast cost changes over the regulatory control period that would meet the opex criteria but are not otherwise captured in base opex or the rate of change.
5. Finally, the AER will **add any other opex** components which have not been forecast using this approach.

I 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*.

With final year expenditure to be equal to:

$$A_f^* = F_f - (F_b - A_b) + non\ recurrent\ efficiency\ gain_b$$

Where

- A_f^* is the best estimate of actual opex for the final year of the preceding regulatory control period;
- F_f is the determined opex allowance for the final year of the preceding regulatory control period;
- F_b is the determined opex allowance for the base year;
- A_b is the amount of actual opex in the base year; and
- $non\ recurrent\ efficiency\ gain_b$ is the non recurrent efficiency gain in the base year

Source: AER, Expenditure forecast assessment guideline for electricity distribution, October 2024, pp. 22-23.

I set out a simple example of the AER's base-step-trend approach in box 2.2 below.

Box 2.2: Example of the base-step-trend assessment approach

Consider an illustrative DNSP with the following characteristics:

- actual opex in the base year (A_b) of $90 million
- determined opex allowance for the final year (F_f) of $103 million
- determined opex allowance for the base year (F_b) of $100 million
- a non recurrent efficiency gain of $5 million
- *a rate of change$_i$* of 2%
- *step changes$_t$* of -$10 million in each year of the regulatory control period

The table below sets out the annual forecast opex using the AER's base-step trend approach

($ real million)	Base year	Final year	Year 1	Year 2	Year 3	Year 4	Year 5
Base year opex	90	98	98	98	98	98	98
Rate of change (cumulative)			*2.0%*	*4.0%*	*6.1%*	*8.2%*	*10.4%*
Rate of change (equivalent $)			2.0	4.0	6.0	8.1	10.2
Step change			-10	-10	-10	-10	-10
Forecast opex allowance			90.0	92.0	94.0	96.1	98.2

Where final year actual opex (A_f^*) is calculated as:

$$\$98m = \$103m - (\$100m - \$90m) + \$5m$$

The AER's opex assessment methodology has been consistently used to assess all electricity transmission and distribution proposals since November 2013.

2.2 The Efficiency Benefit Sharing Scheme

This section summarises the regulatory framework applying to the EBSS, specifically:

- the requirements of the NER relating to the EBSS; and
- the AER's current published EBSS applying to DNSPs.

The AER applies the EBSS to all regulated networks, ie, gas and electricity transmission and distribution networks. The EBSS is required to provide a fair sharing between the DNSP and users of efficiency gains and efficiency losses in a regulatory control period, which are defined as the amount by which the DNSP's total actual opex is less than and exceeds (respectively) forecast opex accepted or substituted by the AER in its distribution determination for that period.[14]

The current form of the EBSS applies in conjunction with:[15]

- the incentives created by the ex-ante determination of the opex allowance, which means that there is no 'claw-back' adjustment at the end of the regulatory control period to account for differences between forecast costs and actual outturn costs – if a NSP can provide the required service at a lower cost than forecast, it benefits by keeping the difference, and, if it exceeds the forecast, it bears the cost of this; and
- the revealed cost approach to forecasting opex, whereby the opex allowance in the following regulatory control period is extrapolated from the NSP's most recent observed expenditure, ie, the base year opex.

Where applied to a DNSP, the EBSS has the following effects:[16]

- gains and losses arising from a temporary change in opex relative to the forecast are retained by the DNSP for a period of six years before the benefits or costs of the temporary underspend or overspend is passed through to customers, ie, a one-off reduction in opex of $100 in year 1 is passed through to customers in year 7 by way of a negative $100 EBSS carryover amount in that year;

[14] NER v236, cl 6.5.8(a).

[15]; AER, *Explanatory Statement | Efficiency benefit sharing scheme for Electricity Network Service Providers*, November 2013, pp 10-11.

[16] AER, *Electricity distribution network service providers | Efficiency benefit sharing scheme | Final Decision*, June 2008, pp 23-28.

- gains and losses arising from a permanent increase or decrease in opex relative to forecast opex are retained by the DNSP for a period of six years, before those gains and losses are passed through to customers, ie, a permanent reduction in opex of $100 per annum in year 1 is retained by the DNSP in each year until year 7, when the opex savings are passed through to customers by way of a permanent reduction in the effective revenue allowance for opex (comprised of the collective effect of the opex allowance and the EBSS carryover amounts) of $100 per annum; and
- the rewards and penalties of any gains or losses is invariant as to the timing within a regulatory control period of the occurrence of those gains/losses.

I set out the approach to determining a DNSP's EBSS incremental efficiency gains specified by the AER's current published EBSS in box 2.3 below.

Box 2.3: Formula for calculating the incremental efficiency under the EBSS

In any year other than the first and the final year of the regulatory control period, the incremental efficiency will be calculated as follows

$$I_{i,n} = (F_{i,n} - A_{i,n}) - (F_{i-1,n} - A_{i-1,n})$$

Where:

- $I_{i,n}$ is the marginal efficiency gain in year *i* of period *n*;
- $F_{i,n}$ is the forecast opex in year *i* of period *n*;
- $A_{i,n}$ is the actual opex in year *i* of period *n*;
- $F_{i-1,n}$ is the forecast opex in year *i-1* of period *n*;
- $A_{i-1,n}$ is the actual opex in year *i-1* of period *n*;

In the final year of the regulatory control period, incremental efficiency will be calculated by the following formula:

$$I_{f,n} = (F_{f,n} - A^*_{f,n}) - (F_{f-1,n} - A_{f-1,n})$$

- f is the marginal efficiency gain in final year of period *n*;
- $F_{f,n}$ is the forecast opex in final year of period *n*;
- $A^*_{f,n}$is estimated actual opex in final year of period *n*;
- $F_{f-1,n}$ is the forecast opex in the penultimate year of period *n*;
- $A_{f-1,n}$ is the actual opex in the penultimate year of period *n*;

Estimated actual opex for the final regulatory year will be calculated as:

$$A^*_{f,n} = F_{f,n} - (F_{b,n} - A_{b,n}) + \ non\text{-}recurrent\ efficiency\ gain_{b,n}$$

- *b* is the year of actual opex in period *n* used as the basis to set forecast opex in period *n+1*
- $non\ recurrent\ efficiency\ gain_{b,n}$ is the non recurrent efficiency gain in the base year of period *n*

Incremental efficiency gain for the first year of the following period:

$$I_{1,n} = (F_{1,n} - A_{1,n}) - [(F_{f,n-1} - A_{f,n-1}) - (F_{b,n-1} - A_{b,n-1})] - non\text{-}recurrent\ efficiency\ gain_{b,n-1}$$

Source: AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013, pp.6-7.

I provide illustrative worked examples of a permanent and temporary efficiency gains in Appendix A.1.

The AER estimates that the benefits of any increase or decrease in opex is shared through the EBSS approximately 30:70 between NSPs and consumers. However, this sharing ratio is dependent on the discount rate (ie, the regulatory WACC),[17] which has fallen substantially since the EBSS developed.

The EBSS applies to almost all opex, with the only exception being expenditure categories that are not forecast using the revealed cost forecasting approach, such as debt raising costs.

In decisions where the AER has concluded that revealed base year opex costs were inefficient, it has suspended the operation of the EBSS.[18]

The EBSS is widely regarded as achieving its stated objective of providing a constant incentive for networks to efficiently reduce opex throughout the regulatory control period. As a result, the opex incentive mechanism was not changed in the AER's 2023 review of incentive mechanisms and is unchanged from the mechanism that the AER has applied since 2013.[19] Further, the changes made to the EBSS in 2013 were limited with the AER stating:[20]

> Having undertaken this review, the EBSS remains largely unchanged. The only changes that will affect how the EBSS operates are changes to the allowed adjustments and exclusions, and accounting for adjustments for one-off factors in the base year when forecasting opex. We have also clarified how we will determine the carryover period.

2.3 Non recurring adjustment in the base year

Note that a non-recurrent adjustment to base year opex will impact both the opex allowance and the EBSS. Box 2.4 provides an illustrative example of the impact on the opex allowance and the EBSS of a $10 million non-recurrent adjustment in the base year (which I assume is the penultimate year of the regulatory control period).

Box 2.4: Example of a non-recurrent adjustment to base year opex

Consider an illustrative DNSP with the following characteristics:

- actual opex in the base year (A_b) of $90 million
- determined opex allowance for the final year (F_f) of $103 million
- determined opex allowance for the base year (F_b) of $100 million
- a non recurrent efficiency gain of $5 million
- *a rate of change$_i$* of 2%

[17] AER, *Electricity transmission network service providers | Efficiency benefit sharing scheme | Final Decision*, September 2007, p 11. Although this version of the EBSS has been superseded by the 2013 EBSS, I consider it appropriate to refer to the AER's 2007 Final Decision. This is because the 2013 updates were limited, such that discussion of EBSS principles in 2007 remains relevant to the present EBSS.

[18] See, for example, AER, *Final Decision | ActewAGL distribution determination 2015-16 to 2018-19 | Attachment 9 – Efficiency benefit sharing scheme*, April 2015, p 9-11; AER, *Final Decision | Ausgrid distribution determination 2015-16 to 2018-19 | Attachment 9 – Efficiency benefit sharing scheme*, April 2015, p 9-19; and AER, *Essential Energy final decision 2015-16 to 2018-19 | Attachment 9 – Efficiency benefit sharing scheme*, April 2015, p 9-18.

[19] AER, *Review of incentives schemes for networks | Final decision*, April 2023, p 30.

[20] AER, *Explanatory Statement | Efficiency benefit sharing scheme for Network Service Providers*, November 2013, p 7.

- *step changes$_t$* of -$10 million in each year of the regulatory control period

The table below sets out the annual forecast opex using the AER's base-step trend approach

($ real million)	Base year	Final year	Year 1	Year 2	Year 3	Year 4	Year 5
Base year opex	90	98	98	98	98	98	98
Rate of change (cumulative)			*2.0%*	*4.0%*	*6.1%*	*8.2%*	*10.4%*
Rate of change (equivalent $)			2.0	4.0	6.0	8.1	10.2
Step change			-10	-10	-10	-10	-10
Forecast opex allowance			90.0	92.0	94.0	96.1	98.2

Where final year actual opex (A_f^*) is calculated as:

$$\$98m = \$103m - (\$100m - \$90m) + \$5m$$

Also assume that, for all previous years, the illustrative DNSP's actual opex matched forecast opex. As a consequence, the EBSS would estimate opex for the final year of $98 million, ie:

$$A_{f,n}^* = \$103\text{m} - (\$100\text{m} - \$90\text{m}) + \$5m$$

This would lead to a marginal efficiency gain in the final year of -$5 million, ie:

$$I_{f,n} = (\$103m - \$108m) - (\$100m - \$90m)$$

He table below illustrates the effective opex allowance which includes EBSS carryover amounts.

($ real million)	Base year	Final year	Year 1	Year 2	Year 3	Year 4	Year 5
Base year opex	90	98	98	98	98	98	98
Rate of change (cumulative)			*2.0%*	*4.0%*	*6.1%*	*8.2%*	*10.4%*
Rate of change (equivalent $)			2.0	4.0	6.0	8.1	10.2
Step change			-10	-10	-10	-10	-10
Forecast opex allowance			90.0	92.0	94.0	96.1	98.2
EBSS carryover amount			-5	-5	-5	-5	-5
Effective opex allowance (including EBSS)			85.0	87.0	89.0	91.1	93.2

This results in comparable financial outcomes to a scenario where a non-recurrent adjustment is not made.

($ real million)	Base year	Final year	Year 1	Year 2	Year 3	Year 4	Year 5
Base year opex	90	93	93	93	93	93	93
Rate of change (cumulative)			*2.0%*	*4.0%*	*6.1%*	*8.2%*	*10.4%*
Rate of change (equivalent $)			1.9	3.8	5.7	7.7	9.7

Step change	-10.00	-10.00	-10.00	-10.00	-10.00
Forecast opex allowance	84.9	86.8	88.7	90.7	92.7
EBSS carryover amount	0	0	0	0	0
Effective opex allowance (including EBSS)	84.9	86.8	88.7	90.7	92.7

The primary difference is the optics of the decision, in that removing the $5 million non-recurrent efficiency gain in the base year results in the DNSP's forecast opex allowance better reflecting its expected expenditure over the regulatory control period.

3. Interpreting the AER's 2026-31 draft decisions

This section examines aspects of the AER's draft decisions for the Victorian DNSPs relating to the opex allowances and the EBSS carryover amounts arising from 2021-26 opex. This section highlights that:

- the AER's 2021-26 decision allowed the Victorian DNSPs a step change in their 2021-26 opex allowances for insurance costs, and, in its draft decisions for these Victorian DNSPs for the 2026-31 regulatory control period, it views their underspend of these allowances in the 2021-26 regulatory control period as being both material and temporary in nature;
- the AER's draft decision includes the following three adjustments specifically related to DNSP insurance costs:
  - a non-recurrent efficiency gain adjustment was included in the EBSS models of the Victorian DNSPs, which resulted in a negative EBSS carryover amount being included in each year of the 2026-31 regulatory control period;
  - a corresponding non-recurrent efficiency gain adjustment was made to base year opex in the opex models of the Victorian DNSPs, which resulted in an increase to the DNSP's opex allowance in each year of the 2026-31 regulatory control period; and
  - a negative step change adjustment was made that decreases the DNSP's opex allowance in each year of the 2026-31 regulatory control period;
- the AER performed the above three steps with the stated aim of:
  - setting a forecast opex allowance equal to that required by a prudent operator;
  - ensuring that the adjustment to the opex allowance for the difference between the final year and the base year does not result in an implicit insurance premium allowance that is 'materially higher than that required by a prudent operator'; and
  - base returning all the 2021–26 insurance premium outperformance to customers, in a manner consistent with all insurance underspends over the 2021-26 regulatory control period being non-recurrent efficiency gains, noting that:[21]

> …[the NSP] retains its share of the insurance premiums underspend as it retains the time value of holding the underspends for 6 years.

3.1 Background to the initial insurance step change

In the 2021-26 final decisions, the AER accepted that forecast insurance premiums for the Victorian DNSPs would be materially higher than in the previous regulatory control period. The AER noted that the information provided by these DNSPs' insurance brokers (Aon and Marsh) in relation to expected insurance premium price increases over the 2021-26 regulatory control period was consistent with opinions from its expert consultant, Taylor Fry. The then prevailing market conditions that led to such forecast increases in insurance premiums were mainly driven by international bushfire claims.[22]

At the time, the AER considered using either cost pass throughs or step changes to implement the opex adjustment, and decided that step changes were more appropriate:[23]

[21] AER, *Attachment 3 – Operating expenditure | Draft decision Powercor distribution determination 2026–31*, September 2025 (Powercor 2026-31 DD), p 36.

[22] AER, *Attachment 6: Operating expenditure | Final decision – Jemena 2021–26*, April 2021 (Jemena 2021-26 FD); AER, *Attachment 6: Operating expenditure | Final decision – AusNet 2021–26*, April 2021 (AusNet 2021-26 FD); AER, *Attachment 6: Operating expenditure | Final decision – Powercor 2021–26*, April 2021 (Powercor 2021-26 FD); AER, *Attachment 6: Operating expenditure | Final decision – United Energy 2021–26*, April 2021 (United Energy 2021-26 FD).

[23] AER, *Final Decision | AusNet Services Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 53.

> We acknowledge the benefits of using a cost pass through for businesses to recover insurance premium costs over the next regulatory control period. These include that a cost pass through lessens the need to set a forecast when there is significant uncertainty and customers only pay for higher costs when they are known during the period. However, we consider on balance that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.

The step changes were considered to align with the incentive based regulation framework, in which DNSPs are encouraged to search for efficient cost outcomes. In concluding that insurance premium step changes were appropriate, the AER observed that:[24]

> This position takes into account:
>
> …
>
> - Consistency with our incentive based regulation framework, where businesses are best incentivised to achieve efficient cost outcomes by including costs in the total opex forecast. An example of this is AusNet Services' decision (after consulting with its customers) to raise its deductible from $10 million to $25 million in order to cut in half the premium increases in its 2020–21 renewal.

The resultant insurance step changes for the entire 2021-26 regulatory control period were (in $2020-21):

- Jemena: $28.2 million (or $34.7 million in $2025-26);
- AusNet: $45.1 million (or $55.4 million in $2025-26);
- Powercor: $67.7 million (or $83.3 million in $2025-26); and
- United Energy: $28.9 million (or $35.5 million in $2025-26).

Table 3-1 sets out the insurance step change for each of the Victorian DNSPs for each regulatory year of the 2021-26 regulatory control period (in $2025-26).

Table 3-1: Allowed insurance step change for the Victorian DNSPs 2021-26 period ($2025-26 million)

	Jun 2022	Jun 2023	Jun 2024	Jun 2025	Jun 2026
Jemena	4.74	6.15	7.38	7.92	8.50
AusNet	5.94	8.42	10.95	13.62	16.49
Powercor	9.55	14.93	18.14	19.56	21.11
United Energy	4.03	6.35	7.74	8.35	9.02

Source: AER, Final Decision | Jemena Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 49, AER,* Final Decision | AusNet Services Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 51, AER,* Final Decision | Powercor Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 37, AER,* Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 35, Australian Bureau of Statistics All groups CPI, Australia, HoustonKemp analysis.*

I note that table 3-1 does not reflect the DNSPs' insurance costs in the base year used for forecasting opex for the 2021-26 regulatory control period. The implicit allowances provided by the AER for insurance costs in 2021-26 will be the sum of both the insurance step change and the DNSPs' insurance costs in the base year.

Table 3-2 sets out the implicit allowance for insurance costs provided by the AER for the 2021-26 regulatory control period (in $2025-26).

[24] AER, *Final Decision | AusNet Services Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 53.

Table 3-2: Implicit allowance for insurance costs 2021-26 period ($2025-26 million)

	Jun 2022	Jun 2023	Jun 2024	Jun 2025	Jun 2026
Jemena	[redacted]				
AusNet	[redacted]				
Powercor					
United Energy					

Source: Jemena information request #011, AusNet information request #016, Powercor information request #020 and United Energy information request #018, AER draft decisions, Australian Bureau of Statistics All groups CPI, Australia, HoustonKemp analysis.

3.2 The draft decisions' claimed approach

In its draft decision for 2026-31 for each of the Victorian DNSPs published on 30 September 2025, the AER concluded that.[25]

- the insurance premiums information supplied by the DNSP shows a significant underspend over the 2021-26 regulatory control period;
- the original insurance step change in 2021-26 is no longer considered by the AER to be perpetual, and, instead, the difference between actual insurance costs and the implied insurance allowance is treated by the AER as non-recurrent in nature:[26]

  > …that the previously approved 2021–26 insurance step changes are not a recurrent step up in costs required in perpetuity (that is, we consider they are non-recurrent)

- the estimate of opex for the final year of 2021-26 will, by design, include the difference between the AER's implicit insurance opex forecasts for each of the final year and the base year, which, in turn, reflect its insurance step changes:[27]
  - including this would make the forecast opex for 2026-31 'materially higher than that required by a prudent operator', and 'would not provide a fair sharing of efficiency gains or losses under the EBSS'; and
  - this increment to the final year opex estimate would need to be removed so that network users do not need to wait for six years before the AER's implicit insurance opex forecasts are no longer reflected in allowed revenue; and
- base year insurance costs, increased for the price growth component of trend, will capture the expected insurance premiums in the 2026-31 regulatory control period:
  - I note that this sentence appeared only in Jemena's and AusNet's draft decisions and not in Powercor's or United Energy's draft decisions; nonetheless,
  - I assume the AER's opinion holds true across all of the Victorian DNSPs.

[25] AER, *Draft decision | Jemena electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, pp 36-38; AER, *Draft decision | AusNet electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, pp 32-34; AER, *Draft decision | Powercor electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, pp 35-36; AER, *Draft decision | United Energy electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, pp 31-32.

[26] AER, *Draft decision | Powercor electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 36.

[27] This is because, as discussed in section 2.3 above (see the description of step 3 of the AER's base-step-trend approach), the AER calculates final year opex by taking forecast final year opex and subtracting the difference between forecast base year opex and actual base year opex (before adding an amount equal to non-recurrent efficiency gains in the base year). This is equivalent to estimating final year opex by taking actual base year opex and adding forecast final year opex net of forecast base year opex (before adjusting for non-recurrent efficiency gains in the base year).

Presumably for these stated reasons, the AER implemented:

- a negative insurance step change, which is 'calculated as the difference between the final year premium allowance and actual premium'; and
- a non-recurrent efficiency gain, which is 'equal to the insurance underspend in the base year'.

The AER claimed that these adjustments would achieve the following results:

- 'forecast opex [would be] equal to that required by a prudent operator';
- 'remov[al of] the expected over forecasting of insurance premiums in 2025–26, thus ensuring this over forecasting isn't continued into the 2026–31 period';
- '[the NSP would] return… all the 2021–26 insurance premium underspends through EBSS decrements six years later (treating the underspends as non-recurrent efficiency gains)'; and
- 'the NSP [would] retain… its share of the insurance premiums underspend as it retains the time value of holding the underspends for 6 years':
  - I note that this sentence appeared only in Powercor's and United Energy's draft decisions and not in Jemena's or AusNet's draft decisions; nonetheless,
  - I assume the AER's opinion holds true across all of the Victorian DNSPs.

I note that the AER neither mentioned nor considered the possibility that the Victorian DNSPs achieved the insurance premium underspend through efficient cost management, in response to the incentives created by the incentive based regulation framework, which was an acknowledged objective of the AER in deciding, in its 2021-26 final decision quoted in the previous section, to allow for the then forecast increase in insurance costs via a step change, rather than a pass through.

3.3 The AER's actual approach in its modelling and its effect

The AER's draft decisions made the following three variations to its normal practice of setting the opex allowances and EBSS carryover amounts, in order to give effect to its decision on the insurance costs of the Victorian DNSPs:

- it included a negative non-recurrent adjustment to the EBSS carryover amounts for the 2026-31 regulatory control period;
- it added the non-recurrent adjustment to the base year opex amount, in its base-step-trend model used to assess the reasonableness of the relevant Victorian DNSPs' opex allowances for the 2026-31 regulatory control period; and
- it included a negative step-change for insurance costs for the 2026-31 regulatory control period.

However, to determine the implicit allowance for insurance costs provided by the AER in its draft decisions, it is necessary to also have regard to:

- the Victorian DNSPs' actual insurance costs in the base year used to set the opex allowances over the 2026-31 regulatory control period; and
- the change provided for insurance costs in the opex allowances between the final year of the 2021-26 regulatory control period (ie, 2025-26) and the base year used to set the opex allowances for the 2026-31 regulatory control period.

3.3.1 Implementation of the AER's approach in its modelling for the 2026-31 regulatory control period

In this section, I outline how the AER implemented its approach described in the draft decision. I first illustrate this for Powercor in tables 3-3 to 3-7, and then provide summaries for all four of the Victorian DNSPs in table 3-8 and table 3-9:.

Step 1: Base year actual insurance costs

The AER first includes Powercor's actual insurance costs in the base year in its opex forecast for the 2026-31 regulatory control period. Powercor's proposal nominates 2024-25 as the base year for use in forecasting opex for 2026-31. After scaling Powercor 's actual insurance opex in the base year by the rate of change for each year of the 2026-31 regulatory control period, which is provided in the AER's opex model accompanying its draft decision for Powercor, the total insurance allowance for Powercor for 2026-31 is [redacted] ($2025-26), as illustrated in the table below.

Table 3-3: Base year insurance costs (Powercor)

$m 2025-26	Jun 2027	Jun 2028	Jun 2029	Jun 2030	Jun 2031	Total
Base year insurance costs	[redacted]					
Rate of change (cumulative)						
Base year insurance costs (trended)						

Source: Powercor information request #020, AER – Opex Model – Draft Decision – Powercor – distribution determination 2026–31 – September 2025

Step 2: Addition of amount equal to non-recurrent efficiency gains in the base year

The AER then adds an amount equal to the AER's assessment of Powercor's non-recurrent efficiency gains for insurance opex in the base year. Since this is an addition to insurance opex in the base year, it must be scaled by the rate of change for Powercor for each year of the 2026-31 regulatory control period. The total insurance allowance for Powercor for 2026-31 attributable to the addition of the AER's assessment of Powercor 's non-recurrent efficiency gains for insurance costs is [redacted] ($2025-26), as illustrated in the table below.

Table 3-4: Addition of non-recurrent efficiency gains in the base year (Powercor)

$m 2025-26	Jun 2027	Jun 2028	Jun 2029	Jun 2030	Jun 2031	Total
Non-recurrent efficiency gains	[redacted]					
Rate of change (cumulative)						
Non-recurrent efficiency gains (trended)						

Source: AER – Opex Model – Draft Decision – Powercor – distribution determination 2026–31 – September 2025

Step 3: Add the estimated change in opex between the base year and the final year

The third step is to add the change in the AER's implicit total forecast of insurance opex between the base year and the final year of the 2021-26 regulatory control period, in its distribution determination for Powercor for 2021-26 (in order to reflect the estimate of insurance opex for the final year in the forecast of insurance opex for 2026-31). As explained in section 3.1 above, the AER's implicit total forecast of insurance opex for each of the base year and the final year is calculated by adding the insurance step change - being [redacted] million and [redacted]n ($2020-21), respectively - and the insurance allowances embedded in the opex forecast, as a consequence of its use of actual base year opex for forecasting 2021-26 opex - being [redacted] million and [redacted] million ($2020-21), respectively. The resulting difference between the final year and base year total insurance allowances is therefore [redacted] ($2020-21), which equates to [redacted] ($2025-26).

After adjusting this figure for the rate of change for Powercor for each year of the 2026-31 regulatory control period, the total insurance allowance for Powercor for 2026-31 attributable to the change in the AER's implicit total forecast of insurance opex between the base year and the final year of the 2021-26 regulatory control period is [redacted] million ($2025-26), as illustrated in the table below.

Table 3-5: Add the estimated change in opex between the base year and the final year (Powercor)

$m 2025-26	Jun 2027	Jun 2028	Jun 2029	Jun 2030	Jun 2031	Total
Differences between final and base year (insurance components)	[redacted]					
Rate of change (cumulative)						
Differences between final and base year (insurance components - trended)						

Source: AER – Opex Model – Draft Decision – Powercor – distribution determination 2026–31 – September 2025

Step 4: Negative insurance step change

Step four is a flat insurance step change applied to each year individually. The total insurance step change for Powercor is -$76.39 million ($2025-26), as illustrated in the table below.

Table 3-6: Negative insurance step change (Powercor)

$m 2025-26	Jun 2027	Jun 2028	Jun 2029	Jun 2030	Jun 2031	Total
Insurance step change	**-15.28**	**-15.28**	**-15.28**	**-15.28**	**-15.28**	**-76.39**

Source: AER – Opex Model – Draft Decision – Powercor – distribution determination 2026–31 – September 2025

Step 5: Adjustment to the EBSS model (deducted in final revenue and does not affect opex)

Step five is another flat change applied to each year individually. However, this step is applied in the EBSS model and, while it affects the total revenue received by Powercor in respect of opex, does not affect the total allowed opex for 2026-31. Instead, it forms part of the calculation in the carryover amounts in the EBSS model, which is one component of Powercor's total revenue allowance. The result of this step appears as a part of the revenue adjustment in the PTRM model for the overall incentive scheme regulated under the NER.[28] The total revenue impact of this step for Powercor is [redacted] ($2025-26), as illustrated in the table below.

Table 3-7: Adjustment to the EBSS model (Powercor)

$m 2025-26	Jun 2027	Jun 2028	Jun 2029	Jun 2030	Jun 2031	Total
Revenue adjustment in PTRM (from EBSS)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: AER – Opex Model – Draft Decision – Powercor – distribution determination 2026–31 – September 2025

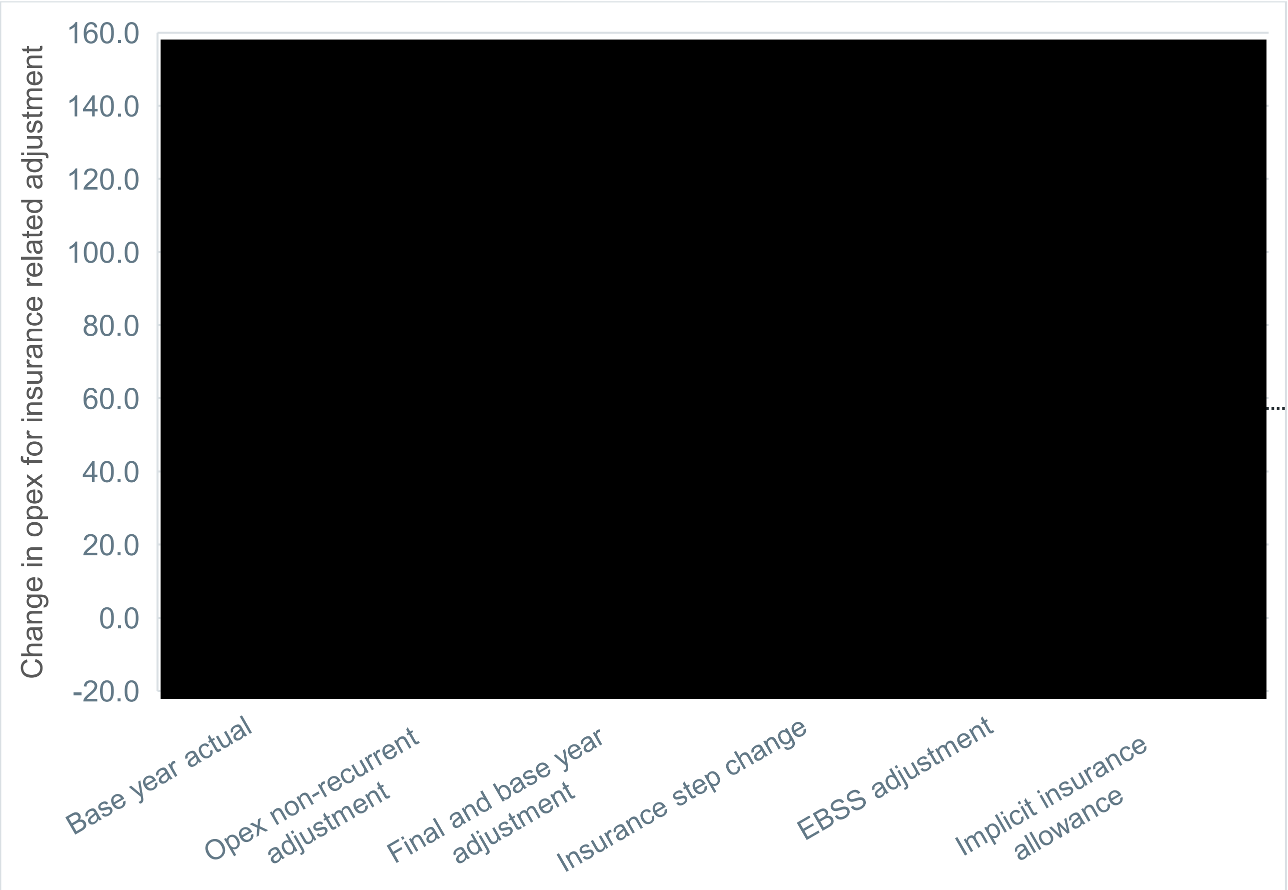
Combining steps one through five, I arrive at an implicit allowance for insurance costs of [redacted] million ($2025-26) for Powercor for the 2026-31 regulatory control period. The AER's adjustments, at steps two to five above, result in a reduction in the insurance allowance for the 2026-31 regulatory control period of - [redacted] ($2025-26). Insofar as Powercor's base year insurance costs (trended) of [redacted] million ($2025-26) (ie step one above) provide a reasonable indication of Powercor's expected insurance costs in

[28] NER v236, 6.4.3(a)(5) & 6.5.8.

the 2026-31 regulatory control period, these AER adjustments (in the amount of [redacted] ($2025-26)) will result in Powercor's opex allowances for the period being insufficient to compensate it for its efficient costs of providing standard control services.

The AER's approach to insurance opex for the 2026-31 regulatory control period is summarised in the waterfall chart in figure 3.1.

Figure 3.1: All insurance related changes in the draft decision for Powercor over the 2026-31 regulatory control period ($m 2025-26)



Source: Powercor information request #020, AER – Opex Model – Draft Decision – Powercor – distribution determination 2026–31 – September 2025

The total change to insurance revenue allowances for the 2026-31 regulatory control period for each of the Victorian DNSPs resulting from the adjustments effected by the AER's draft decisions, described at steps two to five above, are summarised in table 3-8 below.

Table 3-8: Summary of changes in insurance revenue allowances for the 2026-31 regulatory control period for each Victorian DNSP made by AER's adjustments

Step	$m 2025-26	Jemena	AusNet	Powercor	United Energy
Two	Non-recurrent efficiency gains (trended)	[redacted]		[redacted]	
Three	Differences between final and base year (insurance components - trended)	[redacted]		[redacted]	
Four	Insurance step change	[redacted]		[redacted]	
Five	Revenue adjustment in PTRM (from EBSS)	[redacted]		[redacted]	
	Total change	[redacted]		[redacted]	

Again, insofar as the Victorian DNSPs' base year insurance costs (trended) (ie step one above) provide a reasonable indication of their expected insurance costs in the 2026-31 regulatory control period, these AER adjustments will result in the DNSPs' opex allowances for the period being insufficient to compensate them for their efficient costs of providing standard control services.

This is evident from the following table, which discloses the total insurance opex allowances, and the revenue allowances for insurance opex net of the EBSS carryover adjustments, for each of the Victorian DNSPs.

Table 3-9: Summary of insurance revenue allowances for the 2026-31 regulatory control period for each relevant Victorian DNSP

$m 2025-26	Jemena	AusNet	Powercor	United Energy
Insurance cost embedded in base year actual opex (step one)	[redacted]	[redacted]		
Net change for insurance allowance in opex (step two to four)	[redacted]	[redacted]		
Insurance allowances in opex	[redacted]	[redacted]		
Revenue adjustment in PTRM (from EBSS) (step five)	[redacted]	[redacted]		
Net insurance allowances in revenue	[redacted]	[redacted]		

4. Insurance underspends were likely impacted by efficient cost management

The AER's draft decisions conclude that the insurance premium underspends over the 2021-26 regulatory control period by the Victorian DNSPs were non-recurrent efficiency gains. This conclusion implicitly attributes the lower than expected insurance premiums to external factors outside of the control of the businesses and not the result, in whole or in part, from management efforts to efficiently manage their insurance premiums, and in particular their bushfire insurance premiums.

The failure to recognise and reward these management efforts undermines regulatory incentives, and encourages businesses to do nothing to mitigate cost increases by introducing the risk that these efforts will be clawed back through revenue allowances in subsequent regulatory determinations.

In the remainder of this section, I summarise the efforts implemented by Victorian DNSPs to mitigate insurance costs over the 2021-26 regulatory control period.

4.1 Jemena

[redacted]

[29] Lockton, *Jemena Electricity Network (Vic) Ltd Insurance Premium Forecast*, November 2025, at p 31.

[30] DLA, *Letter of engagement*, p 16.

[31] DLA, *Letter of engagement*, pp 16-17.

[32] DLA, *Letter of engagement*, pp15-17.

[redacted]

[33] DLA, *Letter of engagement*, p 17.

[34] DLA, *Letter of engagement*, p 14.

[35] Lockton, *AusNet Electricity Services Pty Ltd Addendum*, 26 November 2025, p 7.

[36] Lockton, *AusNet Electricity Services Pty Ltd Addendum*, 26 November 2025, p 7.

[37] Lockton, *AusNet Electricity Services Pty Ltd Addendum*, 26 November 2025, pp 8-9.

[38] Lockton, *AusNet Services Insurance Premium Forecast*, 29 January 20205, p 10.

[redacted]

[39] DLA, *Letter of engagement*, p 13.

[40] Marsh, *Victoria Power Networks Pty Ltd and United Energy Distribution Pty Ltd Insurance Premium Forecast Report for 2026-2031 Regulatory Control Period*, 26 November 2025, p 22.

[41] Marsh, *Victoria Power Networks Pty Ltd and United Energy Distribution Pty Ltd Insurance Premium Forecast Report for 2026-2031 Regulatory Control Period*, 26 November 2025, pp 24-25.

[redacted]

[42] Marsh, *Victoria Power Networks Pty Ltd and United Energy Distribution Pty Ltd Insurance Premium Forecast Report for 2026-2031 Regulatory Control Period*, 26 November 2025, pp 25-26.

5. Implication of the draft decisions

This section outlines my analysis of the merits of the draft decisions. I find that the draft decisions undermine the objectives and intent of the regulatory regime, as the draft decisions:

- make non-recurrent adjustments and step changes that are inconsistent with the stated reasons for which these adjustments were introduced into the EBSS and opex forecasting methodology;
- implement an ex post decision that reclassifies the Victorian DNSPs' underspends of their implicit insurance allowances for the 2021-26 regulatory control period as 'temporary', which:
  - is inconsistent with the forecast opex and EBSS provisions in the NER, which do not allow for retrospective adjustments for DNSPs' past gains or losses, regardless of the AER's characterisation of those underspends and the drivers of them;
  - is inconsistent with the rationale for, and objectives of, the 2021-26 final decision which acknowledged the uncertainty of forecasting insurance premiums but determined that, on balance, it was appropriate for the regulatory incentives to remain on insurance premiums over the 2021-26 regulatory control period and, therefore, rejected the proposal of an insurance premiums cost pass through event, which would have allowed the AER to claw back material differences in that period between the DNSP's actual insurance premiums and the implicit insurance premiums allowances; and
  - undermines the regulatory ex ante incentives because DNSPs will no longer have the certainty that they will be rewarded for outperforming their opex allowance;
- introduce an asymmetry into the regulatory framework that does not allow DNSPs to have a reasonable expectation of cost recovery;
- undermine the principle of a total opex allowance, which diminishes the incentives DNSPs have to reduce costs efficiently; and
- do not provide for a fair sharing of temporary efficiency gains, and imposes an ex post punishment on Jemena, Powercor and United Energy for underspending their implicit insurance premium allowances over the 2021-26 regulatory control period.

5.1 The opex and EBSS adjustments were inconsistent with the intended purpose of the scheme

The AER's draft decisions include three adjustments specifically related to DNSP insurance costs, ie:

- a non-recurrent adjustment was included in the EBSS models of Victorian DNSPs, which resulted in negative EBSS carryover amounts being included in each year of the 2026-31 regulatory control period;
- a corresponding non-recurrent cost adjustment was made to base year opex in the opex models of Victorian DNSPs, which resulted in an increase to the DNSPs' opex allowances in each year of the 2026-31 regulatory control period; and
- a negative step change adjustment was made that decreases the DNSPs' opex allowances in each year of the 2026-31 regulatory control period.

However, the AER's use of these adjustments is inconsistent with the stated reasons for which these adjustments were introduced into the EBSS and opex model. The remainder of this section reviews the reasons for which a non-recurrent opex adjustment and step change were included in the EBSS and opex model respectively.

5.1.1 Non-recurrent efficiency gain adjustment

Provision for a non-recurrent efficiency gain adjustment in the calculation of carryover amounts arising from the operation of the EBSS was one of the primary changes in the version 2 of the EBSS (November 2013).[43] This was explicitly provided for in the EBSS to deal with circumstances where a DNSP experiences efficiency gains (or losses) in the base year that will not persist into the future.

If, in calculating the base year opex used to forecast opex for the forthcoming regulatory control period, adjustments were not made for such gains (or losses), then this would result in an opex allowance for the period that did not reflect the DNSP's expected efficient operating costs over the period.

The non-recurrent efficiency gain adjustment mechanism addressed a concern raised by networks that:[44]

> …comparing their subsequent expenditure with their opex allowance could make them appear inefficient.

The AER explained that the inclusion of a non-recurrent efficiency gain adjustment mechanism was designed as a:[45]

> … relatively simple and transparent method of taking account of efficiency gains occurring in the base year that will not persist into the future. It will minimise the rewards (penalties) for efficiency gains (losses) being carried forward by the opex forecast rather than the EBSS carryover payments.

In other words, the intention of the non-recurrent efficiency gain adjustment mechanism is to change the optics of the opex decision but not the overall revenue outcome. This point was highlighted by the AER in Box 2.2 of the Explanatory Statement which worked through a simplified example that demonstrated that the revenue outcome was unchanged, whether or not a non-recurrent efficiency gain adjustment was made.[46]

Notwithstanding this stated purpose, the non-recurrent efficiency gain adjustments made in the draft decisions for the Victorian DNSPs did not reflect a finding by the AER that actual insurance costs in the base year will not persist into the future. Instead, the draft decision makes the finding that:[47]

> … the price growth component of trend will capture any increase to insurance premiums from the base year (2024–25).

The AER also explains that it has included a combination of a negative step change and a non-recurrent efficiency gain to remove the insurance premium component of the final year increment:[48]

> To remove the insurance premium component of the final year increment, our alternative estimate for the draft decision includes a combination of a negative insurance step change and a non-recurrent efficiency gain. This ensures our alternative estimate of total forecast opex meets the opex criteria and the EBSS provides a fair sharing of efficiency gains and losses between NSPs and network users.

[43] AER, *Better Regulation | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

[44] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p 15.

[45] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p 15.

[46] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, Box 2.2 - pp 22-23.

[47] AER, *Draft decision | Jemena electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 37.

[48] AER, *Draft decision | Powercor electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 36.

The AER's use of the non-recurrent efficiency gain adjustment, combined with the negative step change, is inconsistent with the purpose of the non-recurrent efficiency gain mechanism in the EBSS.

5.1.2 Step change

The AER’s base-step-trend approach typically begins with the DNSP’s actual opex in the second last year of the regulatory control period (the ‘base year’) which, if deemed efficient, is escalated for the following three changes:[49]

- escalating forecast increases in the size of the network ('scale escalation')
- escalating forecast real cost changes for labour and materials ('real cost escalation')
- adjusting for efficient costs not reflected in the base opex, such as costs due to changes in regulatory obligations and the external operating environment beyond the NSP's control (step changes).

The AER's draft Expenditure Forecast Assessment Guidelines explained that step changes would be included in the AER’s opex forecast because some cost changes would not be captured by the rate of change (ie, scale and real cost escalations) and are necessary to produce an opex forecast that is consistent with the opex criteria.[50]

The insurance step change made in the draft decisions for the Victorian DNSPs did not reflect the incremental change in expected insurance costs over the 2026-31 regulatory control period compared to the DNSPs' actual insurance costs in the base year.[51] Rather, the draft decisions state that the insurance step change:[52]

> … calculated as the difference between the final year premium allowance and actual premium, removes the expected over forecasting of insurance premiums in 2025–26, thus ensuring this over forecasting doesn’t continue into the 2026–31 period.

The negative step change together with the non-recurrent efficiency gain adjustment to base opex, result in negative carryover amounts for the 2026-31 regulatory control period arising from the operation of the EBSS without rendering the resultant opex allowances for the 2026-31 regulatory control period inconsistent with the opex criteria. The effect of this step change is inconsistent with the EBSS statements about the nature and use of a non-recurrent efficiency gain adjustment. Specifically, the inclusion of the non-recurrent efficiency gain adjustment will have a material financial impact on the Victorian DNSPs, compared to a non-recurrent efficiency gain adjustment of the kind provided for by the EBSS, which is intended to have minimal effect on revenue outcomes. Refer to section 3.3.1, where I have set out our modelled revenue impact on the Victorian DNSPs under the draft decisions.

5.2 The use of ex post adjustments for ex ante forecast inaccuracies undermines the incentive regime

The AER’s explicit decision to clawback the Victorian DNSPs' insurance underspends in the 2021-26 regulatory control period:

[49] AER, *Better Regulation | Explanatory statement | Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p 11.

[50] AER, *Better Regulation | Explanatory statement | Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p 37.

[51] AER, *Draft decision | Jemena electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 37.

[52] AER, *Draft decision | Powercor electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 36.

- is inconsistent with the forecast opex and EBSS provisions in the NER, which do not allow for retrospective adjustments for DNSPs' past underspends or overspends, regardless of the AER's characterisation of those underspends and the drivers of them;
- is inconsistent with the rationale for, and objectives of, the 2021-26 final decision, which acknowledged the uncertainty of forecasting insurance premiums but determined that, on balance, it was appropriate for the regulatory incentives to remain on insurance premiums over the 2021-26 regulatory control period; and
- undermines the regulatory ex ante incentives because DNSPs will no longer have the certainty that they will be rewarded for outperforming their opex allowance. The use of ex post adjustments is inconsistent with the NER's forecast opex and EBSS provisions

The AER's reasons for applying a non-recurrent efficiency gain adjustment and negative insurance step change in the draft decisions suggest that it is seeking to make a retrospective adjustment for overestimating insurance premium increases in the 2021-26 regulatory control period. However, the forecast opex and EBSS provisions in the NER do not provide for 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]

Neither clause states that the AER should, or has the discretion to, adjust its opex forecast with the effect of making retrospective adjustments that recoup from the Victorian DNSPs, or penalise the DNSPs for benefiting from, actual opex not increasing as expected. The ex post clawback of underspends on insurance premiums in the 2026-31 regulatory control period is inconsistent with the AER's ex ante regulatory framework.

The practice of not clawing back past overspends or underspends reflects an important regulatory principle that creates an incentive for a DNSP to make efficiency improvements. That is, it encourages DNSPs to change their operations to lower costs so as to retain any difference between actual costs and forecast costs (or reduce the financial penalty that the DNSP wears when forecast costs are lower than actual costs).

However, pairing the no claw-back principle with a fixed regulatory control period will, in the absence of a suitable opex incentive scheme, provide a DNSP with incentives that are inconsistent with the objectives of the regulatory framework, ie, the incentive to delay the implementation of efficiency or cost savings initiatives.

Consequently, the current form of the EBSS is designed to apply alongside the 'no claw-back' principle and the revealed cost approach to forecasting opex, so as to provide a DNSP with constant incentives through time. Where applied to a DNSP, the EBSS has the following impact:

- both temporary and permanent gains and losses arising from underspending and overspending relative to forecast opex are shared between DNSPs and customers; and
- the rate of retention of any gains or losses is *invariant as to the timing* within a regulatory control period of the occurrence of those gains/losses.

The importance of these features was highlighted in the AER's review of incentive schemes, in which the AER stated that the incentive to incur efficient opex is impacted by 3 main factors:[54]

> 1. The ex-ante operating expenditure forecast, which allows network service providers to keep any operating expenditure underspends as profit.

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

[54] AER, *Review of incentive schemes for networks | Discussion paper*, December 2021, p 40.

2. How actual operating expenditure amounts impact forecast operating expenditure in subsequent periods.
3. The rewards or penalties EBSS carryover amounts.

The ex ante regulatory framework addresses a fundamental challenge, namely that regulators cannot directly observe what constitutes efficient behaviour. There are two key dimensions of this information asymmetry, namely:

- regulators cannot observe the non-monetary cost of managerial effort required to achieve efficiency improvements; and
- regulators cannot isolate the effects of managerial effort from other random factors that influence total costs.

Regarding the first point above, non-monetary costs refer to expenses that do not appear in the firm's statutory accounts because they represent costs borne by shareholders from profits. These may include performance-based management remuneration or shareholders' own expenditure on management oversight.

Conversely, the random cost determinants referred to in the second point above include temporal variations that are inherently unpredictable, such as weather events.[55]

Laffont and Tirole present a stylised model in which regulated firms are either efficient or inefficient, but the regulator lacks the information to distinguish between them.[56] Their analysis demonstrates that optimal regulation under incomplete information produces the following outcomes:

- efficient firms exert optimal effort levels and earn economic rent (returns above the cost of capital); and
- inefficient firms exert suboptimal effort and earn zero economic rent (returns equal to the cost of capital).

Given that regulators cannot determine the efficient cost level with certainty, it follows that they also cannot mandate that regulated businesses incur only efficient costs, and so cannot determine a revenue allowance just sufficient to recover efficient costs. Instead, regulators apply incentive structures that induce regulated businesses to reveal more efficient cost levels through their actual performance.

Following such a revelation, the regulator can then adjust their costs downward to share these efficiency gains with consumers.

The AER's ex post adjustments to claw back past insurance underspends are inconsistent with the forecast opex and EBSS provisions in the NER, which do not allow for retrospective adjustments for DNSPs' past underspends or overspends. This is the case regardless of the AER's characterisation of those underspends and the drivers of them, in order that the NER provisions create an incentive for DNSPs to act efficiently in circumstances where the AER cannot directly observe what constitutes that behaviour,

5.2.1 The ex post adjustments are inconsistent with the rationale for and objectives of the AER's decision on the step change for the 2021-26 regulatory control period

While the forecast opex and EBSS provisions in the NER do not allow the AER to impose retrospective adjustments to recoup from DNSPs past opex outperformance, the regulatory framework set out in the NER does include one such mechanism to allow the AER to claw back past losses or gains when a pre-defined event that materially increases or decreases a DNSP’s capex or opex occurs within a regulatory control period.

[55] J.J.Laffont and J.Tirole, *A Theory of Incentives in Procurement and Regulation*, MIT Press, 1993, p 55. Their model defines costs (C) as equal to $\beta - e$, where β is a random variable and e is the cost-reducing effect of managerial effort.

[56] J.J.Laffont and J.Tirole, *A Theory of Incentives in Procurement and Regulation*, MIT Press, 1993, p 59.

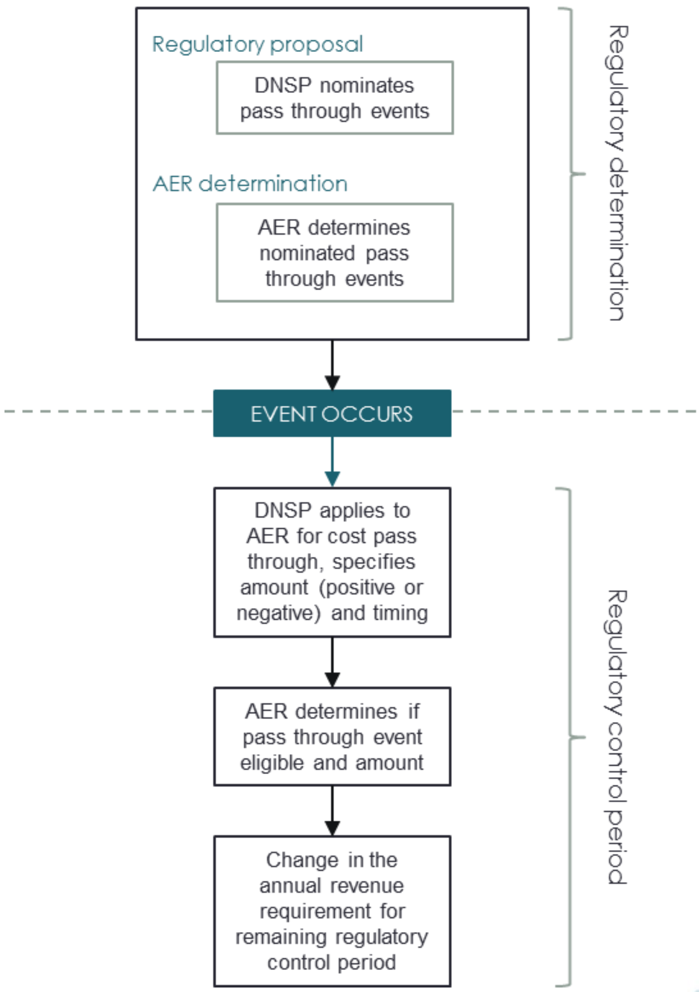
Specifically, clause 6.5.10 of the NER allows DNSPs to nominate unanticipated changes in insurance premiums as a cost pass through event in their regulatory proposal and, where the AER accepts such an event in the DNSP's distribution determination for the regulatory control period, the cost pass through arrangements set out in clause 6.6.1 allow the DNSP to cover the costs incurred as a result of such an event occurring in the regulatory control period.

If the AER had accepted insurance premiums as a cost pass through event in its distribution determinations for the Victorian DNSPs for the 2021-26 regulatory control period, then, in the event of any material increases or decreases in insurance costs within that period, the DNSP could have applied for, and the AER could have approved, a positive (or negative) pass through amount that would have adjusted the DNSP's revenue allowances for the regulatory control period to reflect the efficient costs associated with the event.

Figure 2 provides an overview of the cost pass through arrangements. It shows that the arrangements in the NER fall into two main stages, namely:

- the process for the AER to determine what events are eligible for cost pass through; and
- the process for the DNSP to apply for a cost pass through, if and when an eligible event occurs.

Figure 2 – Overview of cost pass through mechanism



The cost pass through mechanism would have allowed the AER to treat any material change in insurance premiums as temporary had it accepted a nominated pass through event for insurance premiums in its distribution determinations for the Victorian DNSPs for the 2021-26 regulatory control period. Jemena and AusNet in their 2020 regulatory proposals included insurance premiums as a nominated cost pass through event, however, this was rejected by the AER.[57] While Powercor and United Energy in their revised regulatory proposals included insurance premiums as a nominated insurance premiums pass through event, this was also rejected by the AER.[58]

Instead, the AER considered that, on balance, the long term interests of consumers were better served if the standard opex incentives remained on insurance premiums over the 2021-26 regulatory control period.[59]

Thus, the AER potentially could have clawed back the underspends on insurance premiums using the cost pass through mechanism, if it had included insurance premiums as a cost pass through event for the 2021-26 regulatory control period. However, having decided not to do so in its decisions for the 2021-26 regulatory control period, the AER cannot then invoke the negative cost pass through mechanism to claw back the subsequent underspends on insurance premiums.

In effect, the AER's draft decision to claw back the underspends circumvents the NER, by applying a mechanism that the AER is precluded from applying in the present circumstances. It is also inconsistent with the rationale for, and objectives of, the 2021-26 final decision, which acknowledged the uncertainty of forecasting insurance premiums but determined that, on balance, it was appropriate for the regulatory incentives to remain on insurance premiums over the 2021-26 regulatory control period.

5.2.2 The ex post adjustments undermine the ex ante incentives relating to Insurance costs

The AER's 2021 decisions for the Victorian DNSPs neither classified the insurance step increase as temporary, nor indicated that the insurance step change was to apply only for the 2021-26 regulatory control period.

Instead, the insurance step change, like all step changes, represents an expected change to the ongoing costs of the Victorian DNSPs. The draft decisions to reclassify the step change as a 'temporary' efficiency gain thus undermines the ex ante incentives framework.

There is some uncertainty in insurance cost forecasts, and this was acknowledged by the AER when it provided a step change in the 2021-26 regulatory control period.[60]

> On balance, we are of the view that in the current circumstances, while there is some uncertainty associated with forecasting insurance premium increases, we can use the forecasts of future insurance premium increases to include a step change in our alternative estimate.

Notwithstanding this uncertainty, as discussed above, the AER explicitly stated that the regulatory incentives would apply to the insurance step change:[61]

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[57] AER, *Draft Decision | Jemena Distribution Determination 2021 to 2026 | Attachment 15 Pass through events*, September 2020, pp 15-6 and 15-15. AER, *Draft Decision | AusNet Distribution Determination 2021 to 2026 | Attachment 15 Pass through events*, September 2020, pp 15-6 and 15-15.

[58] AER, *Final Decision | Powercor Distribution Determination 2021 to 2026 | Attachment 15 Pass through events, April 2021*, pp 15-11 to 15-13, AER, *Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 15 Pass through events, April 2021*, pp 15-11 to 15-13.

[59] AER, *Final Decision | AusNet Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 6-53.

[60] AER, *Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 6-36.

[61] AER, *Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 6 Operating expenditure*, April 2021, p 6-37.

> … we consider on balance, that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.

In other words, despite the uncertainty of future insurance premiums, the AER affirmed in its 2021 decisions for the Victorian DNSPs that:

- the incentive regime would apply to insurance costs; and
- the Victorian DNSPs would therefore be:
  - rewarded if their operating costs were lower than the implicit allowance; and
  - penalised if their operating costs were higher than forecast.

Further, the AER also specified, in its final decision for the 2021-26 regulatory control period, that version 2 of the EBSS would apply to the Victorian DNSPs.[62]

The introduction of ex post adjustments, such as those in the draft decisions for insurance premiums incurred in the 2026-31 regulatory control period, reduces the ex ante incentives for opex efficiency created by the ex-ante regulatory regime and the EBSS, as DNSPs will no longer have confidence that they will directly benefit from outperforming their opex allowance. That is, the motivation for a DNSP to shoulder the risk of cost-cutting initiatives or invest in efficiency improvements will be diminished if there is a possibility that the regulator will subsequently adjust the DNSP's opex allowance (or reclassify the gains as temporary).

5.3 AER's intended adjustment does not allow for reasonable cost recovery

It follows from the discussion in section 5.2 that the draft decisions to claw back gains from insurance cost increases being less than forecast in 2021 introduces an asymmetric risk that means the Victorian DNSPs do not have a reasonable opportunity to recover their efficient costs.

This asymmetry arises because the AER has only reclassified, on an ex post basis, insurance cost outperformance as temporary, without articulating a general principle as to when material differences between forecast and actual costs will be reclassified as temporary. Specifically, the draft decisions do not consider whether it should reclassify cost increases that were materially higher than forecast as temporary efficiency losses (ie when underperformance will be reclassified as temporary on an ex post basis).

Instead, forecasts that materially underestimate the actual opex costs of the DNSP are treated as perpetual cost increases and subject to higher EBSS penalties. There are a number of examples over the 2021-26 regulatory control period where actual costs were materially higher than forecast over that period, including Powercor's vegetation management costs and AusNet's condition based maintenance costs.[63] These inaccurate forecasts have not been examined by the AER to assess whether they should be reclassified as temporary in nature. Note that any ex-post assessment would necessitate the difficult task of determining whether the difference between forecast and actual costs was due to efficiency/inefficiency of the DNSP, or was caused by factors beyond the control of the DNSP (ie, external factors or random events), the avoidance of the need for which task forms part of the rationale for the EBSS.

A regulatory framework that provides for the retrospective lowering of the rewards for outperformance but does not provide for retrospectively lowering the penalties for underperformance introduces a downward bias in outcomes and, consequently, does not provide DNSPs with a reasonable opportunity to recover their efficient costs.

[62] AER, *Final Decision | Jemena Distribution Determination 2021 to 2026 | Attachment 8 Efficiency benefit sharing scheme*, April 2021, p 8-5., AER, *Final Decision | AusNet Services Distribution Determination 2021 to 2026 | Attachment 8 Efficiency benefit sharing scheme*, April 2021, p 8-5., AER, *Final Decision | Powercor Distribution Determination 2021 to 2026 | Attachment 8 Efficiency benefit sharing scheme*, April 2021, p 8-5. and AER, *Final Decision | United Energy Distribution Determination 2021 to 2026 | Attachment 8 Efficiency benefit sharing scheme*, April 2021, p 8-5.

[63] DLA, *Letter of engagement*, pp 13-14.

As discussed in section 5.2, there are strong economic reasons why regulators do not seek to assess the efficiency of past expenditure, primarily because regulators cannot directly observe what constitutes efficient behaviour. In my opinion, this is one of the main reasons why regulators apply an ex ante regulatory framework.

5.4 The draft decisions undermine the total opex regime

The NER require DNSPs to propose the total forecast opex required to achieve five opex objectives for the regulatory control period.[64] 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.[65]

In other words, the AER is required to form a view on total forecast opex for the forthcoming regulatory control period, rather than on subcomponents such as individual projects or programs (ie, it remains for the DNSP to prioritise its expenditure within the approved opex budget). As a consequence, DNSPs receive a single total opex allowance, rather than several allowances for different subcomponents such as individual projects or programs. This tacitly accepts that there is uncertainty in forecasting costs for individual opex subcomponent and, while the costs for some opex subcomponents may be higher than forecast, others will be lower than forecast.

It is then up to the DNSP to prioritise its expenditure within the approved total opex allowance. This point was emphasised by the AER in a decision for ActewAGL Distribution:[66]

> We do not seek to interfere in the discretion a service provider has as to how and when to spend its total opex forecast to run its network. The service provider is free to decide how to manage its activities in light of the revenue recovered from consumers that we approve.

The provision of a total opex allowance that the DNSP must spend within underpins the incentive properties of the regulatory regime, with the AEMC stating, in making its 2012 rule change for the economic regulation of network service providers:[67]

> The level, rather than the specific contents, of the approved expenditure allowances underpin the incentive properties of the regulatory regime in the NEM. That is, once a level of expenditure is set, it is locked in for a period of time, and it is up to the NSP to carry out its functions as it sees fit, subject to any service standards.

The draft decisions, which effectively establish an insurance cost subcomponent allowance:

- ignore the uncertainty of forecasting costs for individual opex subcomponents and that DNSPs will outperform on some opex subcomponents and underperform on others but must manage their overall opex within their budget; and
- diminish the incentives the Victorian DNSPs have to efficiently reduce costs.

The lessening of the incentives arises because the DNSPs will be disincentivised from managing their risk/efficiency as a whole. I understand that opex costs for DNSPs are interrelated, for example, the impact of bushfires can be addressed in a number of ways. The DNSPs can:

- take out bushfire insurance to compensate them for the damage arising from bushfires caused by the network;

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

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

[66] AER, *Final Decision | ActewAGL distribution determination 2015−16 to 2018−19 | Attachment 7 – Operating expenditure*, April 2015, p 1-82.

[67] AEMC, *Rule Determination | National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p 93.

- mitigate their chance of causing a bushfire by increasing the effectiveness of their vegetation management (either by increasing the amount of vegetation removed or better targeting their vegetation mitigation efforts);
- invest in REFCLs which prevent high voltage powerlines starting bushfires; or
- increase the replacement of wooden poles which decreases the risk of bushfires.

However, instituting an insurance cost subcomponent will mean that a DNSP will be hesitant to manage its bushfire risks by reducing its bushfire insurance costs while investing in other mitigation measures, even when it is efficient to do so. DNSPs will fear that the expected benefits of reducing their insurance costs may, on an ex post basis, be lost, while they continue to bear the full cost of the investment in bushfire mitigation measures.

5.5 The draft decisions do not provide a fair sharing of temporary efficiency gains

In the draft decisions for the Victorian DNSPs, the AER described its intended result of the adjustments as:[68]

> Together, this results in:
>
> - forecast opex equal to that required by a prudent operator
> - Powercor returning all the 2021–26 insurance premium underspends through EBSS decrements 6 years later (treating the underspends as non-recurrent efficiency gains). Powercor retains its share of the insurance premiums underspend as it retains the time value of holding the underspends for 6 years.

That is, the AER states that the intended effect of its insurance premium adjustments in the draft decisions is to treat the Victorian DNSPs' insurance underspends in each regulatory year of the 2021-26 regulatory control period as non-recurring, or temporary, efficiency gains, such that the DNSPs return those underspends through EBSS carryover amounts 6 years after they occur, with the DNSPs retaining the time value of holding the underspends for 6 years.

However, our analysis discloses that the AER's adjustments do not achieve outcomes consistent with the application of the EBSS applicable to the Victorian DNSPs in the 2021-26 regulatory control period where, consistent with the AER's stated intent, the DNSPs' insurance underspends in each regulatory year of the period are treated as non-recurrent, or temporary, efficiency gains, rather than perpetual efficiency gains. Indeed, the decisions for Jemena, Powercor and United Energy effect a revenue outcome that does not simply claw back the over forecasting of insurance premiums in the 2021-26 regulatory control period, it punishes them for underspending those forecasts.

Based on the AER's stated intention for its insurance premium adjustments, I have reconstructed, for each of the Victorian DNSPs, the expected net impact on the revenue allowances for insurance opex for the 2026-31 regulatory control period (inclusive of the implicit insurance opex allowance and the EBSS carryover amounts) of the insurance underspends in the 2021-26 regulatory control period.

That is, I calculate the present value of the underspends of the implicit insurance opex allowance for each regulatory year of the 2021-26 regulatory control period, net of the impacts of the associated EBSS carryover amounts accruing over the six subsequent regulatory years – under each of the following scenarios:

[68] AER, *Draft decision | Jemena electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 38., AER, *Draft decision | AusNet Services electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 34., AER, *Draft decision | Powercor electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 36., AER, *Draft decision | United Energy electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 32.

- where the underspends in each regulatory year of the 2021-26 regulatory control period are treated as temporary efficiency gains in the manner specified by the EBSS applicable to the Victorian DNSPs in that period; and
- where the AER's adjustments specified in the draft decisions for the Victorian DNSPs are made.

If the AER treated Powercor's insurance opex underspend in each year of the 2021-26 regulatory control period as temporary in the manner provided for in the applicable EBSS, then the resultant efficiency gain made by Powercor in each regulatory year would be returned to customers six years after the gain was made. In other words, the underspend in 2021-22 of [redacted] ($2025-26) would be returned to customers in 2027-28.

I first illustrate this for Powercor in table 5-1 and table 5-2, before providing corresponding summaries for all four of the Victorian DNSPs in table 5-3.

Table 5-1 sets out the financial implications for Powercor if the outperformance on insurance costs were considered temporary under the current incentive regime as set out by the EBSS, namely:

- the second column sets out the insurance opex allowances implicit in the total opex allowances set by the AER for Powercor for the 2021-26 regulatory control period (expressed in $m 2025-26);[69]
- the third column sets out Powercor's actual and estimated insurance costs for each regulatory year of the 2021-26 period; and
- the fourth column sets out Powercor's underspend of its implicit insurance opex allowance for each regulatory year of the 2021-26 regulatory control period, and the subsequent EBSS carryover amounts consistent with temporary opex outperformance to consumers, ie, the negative EBSS carryover amount six years after the temporary outperformance.

That is, table 5-1 reproduces the outcomes under the EBSS model for a temporary opex outperformance where the DNSP retains the benefits of a temporary outperformance for a period of six years (including the year that the outperformance occurs) before the EBSS returns that outperformance (by way of a negative carryover amount) to consumers.

As shown in the last two rows of table 5-1:

- the present value of Powercor’s underspend of its implicit insurance opex allowance in each regulatory year of the 2021-26 regulatory control period (calculated using the real vanilla WACC determined by the AER set out in the fifth column) is [redacted] ($2025-26); and
- the expected net present value of Powercor's underspend of its implicit opex allowance in each regulatory year of the 2021-26 regulatory control period, and the subsequent return of the gain to consumers, calculated using the real vanilla WACCs set out in the fifth column, would be [redacted] ($2025-26).

This is consistent with the principle that consumers receive the majority of the benefits attributable to any temporary efficiency outperformance.

[69] This was calculated by summing the insurance allowance embedded in the base opex before step changes, and the step changes in the 2021-26 regulatory period. The insurance allowance embedded in the base opex is taken from the base year of the 2016-20 regulatory period, and escalate by the appropriate rate of change and CPI.

Table 5-1: Expected net impact of EBSS treatment of underspends as temporary efficiency gains on revenue allowances for insurance (Powercor)

$m 2025-26	Implicit insurance opex allowances	Actual insurance costs	Underspends and EBSS carry forward amounts	Real vanilla WACC[70]
Jun 2022	[redacted]			
Jun 2023				
Jun 2024				
Jun 2025				
Jun 2026				
Jun 2027				
Jun 2028				
Jun 2029				
Jun 2030				
Jun 2031				
Jun 2032				
Sum of underspend and EBSS carry forward amounts			[redacted]	
NPV of the insurance opex underspends in 2021-26				
Expected NPV reward for Powercor for temporary gains				

However, based on the actual and forecast insurance costs for Powercor in the 2021-26 and 2026-31 regulatory control periods, I are unable to arrive at the expected outcome described above from the application of the AER's adjustments specified in the draft decisions for the relevant Victorian DNSPs. Table 5-2 outlines how I estimated the net impact for Powercor of the draft decision.

Table 5-2 sets out:

- the insurance opex allowances implicit in the total opex allowances set by the AER for Powercor for each of the 2021-26 regulatory control period and the 2026-31 regulatory control period (expressed in $m 2025-26), in the second column;
- Powercor's actual and estimated insurance costs for each regulatory year of the 2021-26 regulatory control period and the 2026-31 regulatory control period, on the assumption that, for each regulatory year of the 2026-31 regulatory control period, actual opex insurance costs will be equal to the implicit insurance opex allowance for that year, in the third column;[72]
- the differences between the implicit insurance opex allowances and Powercor's actual/estimated costs, in the fourth column;
- the negative EBSS carry forward amount attributable to the non-recurrent insurance costs for each regulatory year of the 2026-31 regulatory control period resulting from the treatment of these as temporary efficiency gains, in accordance with the treatment intended by the draft decision, in the fifth column;

[70] AER, *PTRM – Draft Decision – Powercor Services – distribution determination 2026-31 – September 2025.xls*; and AER, *AER – Powercor Services Distribution PTRM – 2025-26 Return on debt updated (inc VEBM CPT) – March 2025.xls*.

[71] I have assumed that the real WACC in the 2031-32 regulatory year is unchanged from that estimated for the 2030-31 regulatory year.

[72] The draft decision states that the opex would equal that required by a prudent operator. See AER, *Draft decision | Powercor electricity distribution determination 1 July 2026 – 30 June 2031 | Attachment 3 – Operating expenditure*, September 2025, p 36.

- the opex revenue adjustment for each regulatory year of the 2031-36 regulatory control period, resulting from the application of the EBSS to Powercor in the 2026-31 regulatory control period[73], in the sixth column;
- the expected net impact on the revenue allowances for insurance opex (inclusive of the implicit insurance opex allowance and the EBSS carryover amounts) of the insurance underspends in 2021-26 from the application of the AER's adjustments specified in its draft decision for Powercor, derived by summing the figures in columns four through six for each regulatory year, in the seventh column; and
- the real vanilla WACC as determined by the AER for the 2021-26 regulatory control period and in its draft decision for the 2026-31 regulatory control period for Powercor, in the final eighth column.[74]

The sixth column is necessary as Powercor will incur EBSS carryover amounts in 2031-32, as a result of how the EBSS carryover amount is calculated in the first year of the 2026-31 regulatory control period. I have estimated this amount using the 2013 EBSS explanatory statement.[75]

The estimated net impact on Powercor's revenue allowances for insurance opex resulting from the application of the AER's adjustments for Powercor's insurance underspends in the 2021-26 regulatory control period is a penalty for Powercor, in net present value terms, of [redacted] million ($2025-26). This is [redacted] million ($2025-26) below the fair sharing that Powercor should receive, if the insurance underspends in each regulatory year of the 2021-26 regulatory control period were treated as temporary efficiency gains in accordance with the EBSS applicable to the Victorian DNSPs in that period. That is, putting aside the merits and legality of the AER's draft decision, the revenue outcomes of that decision are not consistent with what I would expect to see under application of version 2 of the EBSS, with Powercor being worse off under the AER's decision than it should be if the insurance premium underspends in the 2021-26 regulatory control period are treated as non-recurrent efficiency gains.

[73] AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, pp 6-7.

[74] I assume that the real vanilla WACC in 2031-32 is unchanged from 2030-31.

[75] Calculation based on AER, *Better regulation Explanatory Statement - Efficiency benefit sharing scheme for electricity network service providers*, November 2013, pp 20-21.

Table 5-2: Estimated net impact of AER draft decision on revenue allowances for insurance (Powercor)

$m 2025-26 (1)	Implicit insurance opex allowances (2)	Actual/estimated insurance costs (3)	Differences between allowances and actual/estimate (4)	Revenue adjustment for 2026-31 (EBSS) (5)	Revenue adjustment for 2031-36 (EBSS) (6)	Net impact on revenues allowed for insurance opex (7)	Real vanilla WACC (8)
Jun 2022	[redacted]						
Jun 2023							
Jun 2024							
Jun 2025							
Jun 2026							
Jun 2027							
Jun 2028							
Jun 2029							
Jun 2030							
Jun 2031							
Jun 2032							
NPV of the insurance opex underspends in 2021-26						[redacted]	
Estimated NPV reward (penalty) for Powercor for temporary gains provided by draft decision over 2021-36							
Difference to expected NPV reward (penalty) for temporary gains under EBSS [redacted]							

Appendix A2 includes analogous tables that set out the estimated net impact on revenue allowances for insurance opex for Jemena, AusNet and United Energy resulting from the application of the AER's adjustments in their draft decisions for their insurance underspends in the 2021-26 regulatory control period.

Table 5-3 below summarises the estimated net impact on revenue allowances for insurance opex for all four of the Victorian DNSPs resulting from the application of the AER's adjustments for their insurance underspends in the 2021-26 regulatory control period, in net present value terms. It shows that, based on the information provided in the AER's draft decisions, the DNSPs' actual insurance costs in the 2021-26 regulatory control period and the assumption that their actual insurances costs are equal to their implicit allowances for the 2026-31 regulatory control period, the estimated net revenue impact for each of the DNSPs of the application of the AER's adjustments is less than the reward for the 2021-26 insurance underspends expected from the application of the EBSS, where those underspends are treated as temporary efficiency gains.

[76] This is calculated based on the formula described in.Box 2.3 regarding the incremental efficiency gains in the first regulatory year. It is calculated as [redacted] which is the amount of inefficiency carried over from June 2027. I note that this inefficiency is mostly driven by the reduction of the non-recurrent efficiency gain of [redacted].

[77] I have assumed that the real WACC in the 2031-32 regulatory year is unchanged from that estimated for the 2030-31 regulatory year.

Table 5-3: Summary of net impact of AER draft decision on revenue allowances for insurance for each of the Victorian DNSPs

$m 2025-26	Jemena	AusNet	Powercor	United Energy
NPV of insurance opex underspends in 2021-26	[redacted]	[redacted]		
Expected NPV reward for temporary gains under EBSS				
Estimated NPV reward/penalty for temporary gains provided by draft decisions				
Difference to expected NPV reward for temporary gains under EBSS				

Source: Jemena, AusNet, Powercor and United Energy; AER draft decisions, and HoustonKemp analysis of AER draft decision.

Table 5-3 highlights that the AER's draft decisions do not achieve outcomes consistent with the application of the EBSS applicable to the DNSPs in the 2021-26 regulatory control period where, consistent with the AER's stated intention, the DNSP's insurance underspends in each regulatory year of the 2021-26 regulatory control period are treated as non-recurrent or temporary, rather than perpetual, efficiency gains.

Further, the decisions for Jemena, Powercor and United Energy disclose that the insurance revenue outcomes under the AER's draft decisions represent not simply a “claw back” of the over-forecasting of insurance opex in the 2021-26 final decisions, as a consequence of the ex ante insurance step change, but an ex post punishment of their underspends of those forecasts.

6. Declaration

As part of the letter of engagement, I have been provided with a copy of the Practice Note and the Code.

I acknowledge, for the purposes of the Practice Note and the Code, that I have read the Code, that I agree to be bound by it, and that my report has been prepared in accordance with the Code.

In accordance with the requirements of the Code, I declare that I have made all inquiries that I believe are desirable and appropriate, and that no matters of significance that I regard as relevant have, to my knowledge, been withheld from the Court.

Brendan Quach

27 November 2025

A1. Illustrative worked examples of the EBSS

The appendix sets out two illustrative worked examples of a DNSP making either a permanent efficiency gain (ie, an ongoing reduction in opex relative to forecast opex) or a temporary efficiency gain (ie, a single year non recurrent reduction in opex relative to forecast opex)

A1.1 EBSS treatment of a permanent efficiency gain

In this example, I assume that the regulatory control period and the EBSS carryover period are five years long, and that forecast opex is $200 million in each year. All figures are expressed in real year 1 dollars. During this period, the DNSP delivers opex equal to the forecast for the first two years. Then, in the third year, it implements a more efficient maintenance approach that delivers opex at $190 million each year for the foreseeable future (for simplicity, I have assumed no non-recurrent gains in the base year and no changes to scale, real prices or productivity).

Through the EBSS mechanism, the DNSP will receive additional carryover amounts so that it will receive the benefit from the efficiency improvement for six years (ie, the year in which the gain occurred, plus the additional five year carryover period). It automatically retains the $10 million incremental gain in years 4 and 5 because the allowance for those years are set on an ex ante basis. Because the DNSP made an incremental efficiency improvement of $10 million in year 3, it will receive annual EBSS carryover amounts of $10 million in the first three years of the second regulatory control period (ie, years 6 to 8).

As a result of these effects, the DNSP will benefit from the efficiency improvement from years 3 to 8 because the annual amount the DNSP receives from the forecast opex inclusive of the actual EBSS carryover amounts in years 6 to 8 ($200 million) is more than its actual opex ($190 million) in each of these years. Consumers will benefit from year 9 onwards, after the EBSS carryover period has expired. This is because what consumers pay through the forecast opex and EBSS building blocks ($190 million) is lower from year 9 onwards.

The table A1.1 below provides a more detailed illustration of how the benefits are shared between DNSPs and consumers over time.

Table A1.1: EBSS treatment of a permanent efficiency gain

Year	Regulatory Period 1					Regulatory Period 2					Future
	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t) ($m)	200	200	200	200	200	190	190	190	190	190	pa
Actual (A_t) ($m)	200	200	190	190	190	190	190	190	190	190	pa
Underspend ($F_t – A_t = U_t$) ($m)	0	0	10	10	10	0	0	0	0	0	0 pa
Incremental gain ($I_t = U_t – U_{t-1}$) ($m)	0	0	10	0	0	0	0	0	0	0	0 pa
Carryover (I_1) ($m)		0	0	0	0	0					
Carryover (I_2) ($m)			0	0	0	0	0				
Carryover (I_3) ($m)				10	10	10	10	10			
Carryover (I_4) ($m)					0	0	0	0	0		
Carryover (I_5) ($m)						0	0	0	0	0	

Year	Regulatory Period 1					Regulatory Period 2					Future
	1	2	3	4	5	6	7	8	9	10	
Carryover amount (C_t) (\$m)						10	10	10	0	0	0 pa
Benefits to DNSP ($F_t – A_t + C_t$) (\$m)	0	0	10	10	10	10	10	10	0	0	0 pa
Benefits to consumers ($F_1 – (F_t + C_t)$) (\$m)	0	0	0	0	0	0	0	0	10	10	10 pa

A1.2 EBSS treatment of a temporary efficiency gain

In this example, I adopt the same assumption above, however, in the third year, circumstances mean that its maintenance approach delivers opex of $190 million in that year before returning to forecast opex of $200 million for the foreseeable future (again I have assumed no non-recurrent gains in the base year and no changes to scale, real prices or productivity).

Through the EBSS mechanism, the DNSP will receive additional carryover amounts so that it will receive the benefit from the efficiency improvement for six years (ie, the year in which the gain occurred, plus the additional five year carryover period). Because the DNSP made an efficiency improvement of $10 million in year 3, it will receive annual EBSS carryover amounts of $10 million in the first three years of the second regulatory control period (ie, years 6 to 8). It automatically retains the $10 million incremental gain in years 4 and 5 because the allowance for those years are set on an ex ante basis.

However, because this efficiency gain was only temporary, the DNSP incurs an incremental efficiency loss in year 4 of $10 million (ie, in year 4, the DNSP's opex outcome returned to forecast levels which is a worse outcome than in year 3, where the DNSP's opex outcome was $10 better than forecast). It automatically retains the $10 million penalty in year 5 because the allowance for that year is set on an ex ante basis. Because the DNSP made an incremental efficiency loss of $10 million in year 4, it will receive annual EBSS carryover amounts of -$10 million in the first four years of the second regulatory control period (ie, years 6 to 9).

As a result of these effects, the DNSP will benefit from the efficiency improvement realised in year 3 because the annual amount the DNSP receives from the forecast opex ($200 million) is more than its actual opex ($190 million), while in years 4 and 5 its actual opex matches its opex allowance. Consumers will benefit from year 9, after the positive EBSS carryover period has expired whilst the negative EBSS carryover period still applies. In effect, the DNSP is able to retain the temporary efficiency gain of $10 million for a period of seven years before passing the efficiency gain through to consumers (ie, the DNSP receives a $10 million reward in year 3 for underspending its allowance but then passes that gain to consumers in year 9 by way of an EBSS carryover amount of -$10 million). Put another way, the DNSP retains the time value of holding the underspend in year 3 for 6 years.

The table A1.2 below provides a more detailed illustration of how the benefits are shared between DNSPs and consumers over time.

Table A1.2: EBSS treatment of a temporary efficiency gain

Year	Regulatory Period 1					Regulatory Period 2					Future
	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t) ($m)	200	200	200	200	200	200	200	200	200	200	pa
Actual (A_t) ($m)	200	200	190	200	200	200	200	200	200	200	pa
Underspend ($F_t - A_t = U_t$) ($m)	0	0	10	0	0	0	0	0	0	0	0 pa
Incremental gain ($I_t = U_t - U_{t-1}$) ($m)	0	0	10	-10	0	0	0	0	0	0	0 pa
Carryover (I_1) ($m)		0	0	0	0	0					
Carryover (I_2) ($m)			0	0	0	0	0				
Carryover (I_3) ($m)				10	10	10	10	10			
Carryover (I_4) ($m)					-10	-10	-10	-10	-10		
Carryover (I_5) ($m)						0	0	0	0	0	
Carryover amount (C_t) ($m)						0	0	0	-10	0	0 pa
Benefits to DNSP ($F_t - A_t + C_t$) ($m)	0	0	10	0	0	0	0	0	-10	0	0 pa
Benefits to consumers ($F_1 - (F_t + C_t)$) ($m)	0	0	0	0	0	0	0	0	10	0	0 pa

A2. Additional net impact tables for Jemena, AusNet and United Energy

A2.1 Jemena

[redacted]

[78] This is calculated based on the formula described in.Box 2.3 regarding the incremental efficiency gains in the first regulatory year. It is calculated as [redacted], which is the amount of inefficiency carried over f[redacted].

[79] I have assumed that the real WACC in the 2031-32 regulatory year is unchanged from that estimated for the 2030-31 regulatory year.

A2.2 AusNet

[redacted]

[80] This is calculated based on the formula described in.Box 2.3 regarding the incremental efficiency gains in the first regulatory year. It is calculated as [redacted] which is the amount of inefficiency carried over from June 2027. Note that AusNet's base year is the year ending June 2023.

[81] I have assumed that the real WACC in the 2031-32 regulatory year is unchanged from that estimated for the 2030-31 regulatory year.

A2.3 United Energy

[redacted]

[82] This is calculated based on the formula described in.Box 2.3 regarding the incremental efficiency gains in the first regulatory year. It is calculated as [redacted], which is the amount of inefficiency carried over from June 2027. I note that this inefficiency is mostly driven by the reduction of the non-recurrent efficiency gain of [redacted].

[83] I have assumed that the real WACC in the 2031-32 regulatory year is unchanged from that estimated for the 2030-31 regulatory year.

Annexure A – Letter of engagement

Confidential
Brendan Quach
Senior Economist
Houston Kemp
Level 40, 161 Castlereagh Street, Sydney NSW 2000

Your reference

Our reference
BRE/BRE/395840/76
AUM/1302123676.1

By Email

26 November 2025

Dear Brendan

Letter of engagement for Houston Kemp - DNSP Insurance Opex

1 We act for AusNet Electricity Services Pty Ltd (**AusNet**), Jemena Electricity Networks (Vic) Ltd (**Jemena**), Powercor Australia Ltd (**Powercor**) and United Energy Distribution Pty Ltd (**United Energy**) (together, the **Victorian DNSPs**).

2 As further explained below, the Victorian DNSPs are currently undergoing their 'regulatory resets' for the regulatory control period (**RCP**) commencing on 1 July 2026 and ending on 30 June 2031 (**2026 – 2031 RCP**), and the Australian Energy Regulator (**AER**) has recently released its draft decisions on each DNSP's distribution determination for the RCP (**Draft Decisions**). As part of its Draft Decisions, the AER has set out its proposed approach to each DNSP's operating expenditure (**opex**), including insurance-related opex, for the 2026 – 2031 RCP.

Background

3 The background documents provided to you as appendices to this engagement letter are listed in the Document Index set out in Attachment 1 to this letter.

2026 – 2031 Regulatory Reset Process

4 The Victorian DNSPs are subject to economic regulation under Chapter 6 of the National Electricity Rules (**NER**). Every five years, the AER makes a distribution determination for each Victorian DNSP for the upcoming RCP, which (among other things) determines the DNSP's required revenue for the provision of its regulated services (referred to as 'standard control services'), which it can recover from electricity consumers for the provision of those services during that RCP. The Victorian DNSPs are nearing the end of the current RCP which commenced on 1 July 2021 and ends on 30 June 2026 (**2021 – 2026 RCP**), and are currently engaging with the AER in the regulatory reset process for the upcoming 2026 – 2031 RCP.

5 At a high level, the regulatory reset process for the 2026 – 2031 RCP involves the following key steps:

5.1 *Submission of regulatory proposal* – each Victorian DNSP submitted a regulatory proposal to the AER on 31 January 2025, which contained (among other matters) the proposed total revenue that it requires to provide standard control services, and seek to recover from consumers for the provision of those services, during the forthcoming RCP (referred to as the 'total revenue requirement'). The proposed total revenue requirement is determined using a building block approach, under which the building blocks include, relevantly:

(a) opex forecast to be incurred in the provision of standard control services; and

(b) the revenue increments or decrements (if any) (**carryover amounts**) arising from the operation of any applicable (among other incentive schemes) efficiency benefit sharing scheme (**EBSS**).

5.2 *Making of draft decision by the AER* - On 30 September 2025, the AER released its Draft Decision on each Victorian DNSP's distribution determination for the 2026 – 2031 RCP. Relevantly, the AER's Draft Decision for each Victorian DNSP included draft 'constituent decisions' regarding its proposed forecast opex (including forecast insurance-related opex) for the 2026 – 2031 RCP. The AER did not accept any of the Victorian DNSPs' proposed total forecast opex, rather, it set out its own opex forecasts.

5.3 *Submission of revised regulatory proposal* - No more than 45 business days after the AER publishes its Draft Decision, each Victorian DNSP will submit a revised regulatory proposal to the AER. The revised regulatory proposal may reflect or respond to the AER's feedback provided in the Draft Decision, including through the proposal of updated opex forecasts. The revised regulatory proposal is due by 1 December 2025.

5.4 *Making of distribution determination by AER* - The AER is required to publish its final distribution determination for each Victorian DNSP for the 2026 – 2031 RCP by 30 April 2026.

AER's constituent decision on forecast opex and its general approach to assessing forecast opex

6 The AER is required to make a constituent decision, in a distribution determination for a DNSP for a RCP, on total of the forecast operating expenditure for the RCP (NER, clause 6.12.1(d)).

7 The AER must accept the forecast of required opex of a DNSP if the AER is satisfied that the total of the forecast opex for the RCP reasonably reflects each of the following:

7.1 the efficient costs of achieving the operating expenditure objectives set out in clause 6.5.6(a) of the NER (**opex objectives**);

7.2 the costs that a prudent operator would require to achieve the opex objectives; and

7.3 a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the opex objectives,

(together, the **opex criteria**) (NER, clause 6.5.6(c)).

8 If the AER is not so satisfied, it must not accept the forecast of required opex of a DNSP (NER, clause 6.5.6(d)). If it does not accept the total of the forecast opex for the RCP, the AER must set out an estimate of the total of the DNSP's required opex for the RCP that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors (NER, clause 6.12.1(d)).

9 The AER has published the *Expenditure Forecast Assessment Guideline for Electricity Distribution* dated October 2024 (**Expenditure Forecast Assessment Guideline**), which sets out (among other things) the AER's general approach to assessing a DNSP's proposed opex forecast. A copy of the Expenditure Forecast Assessment Guideline and the accompanying Final Decision and Explanatory Statement is attached as Appendices 3 - 5.

10 The AER generally applies a 'base-step-trend' approach to forecasting opex, under which: [1]

1 AER, Expenditure Forecast Assessment Guideline, page 22.

10.1 *'base'* - actual opex incurred in a recent year (referred to respectively as 'base opex' and the 'base year') is adopted as a starting point (provided the AER is satisfied that the base opex is efficient and prudent), and adjusted to provide an estimate of opex for the final year of the RCP, address any non-recurring opex and exclude any actual opex for opex categories for which opex is forecast or recovered in another manner;

10.2 *'trend'* - the estimated final year opex is then 'trended' forward to the upcoming RCP by applying the 'rate of change' to account for the forecast growth in output, prices and productivity; and

10.3 *'step'* - step changes in prudent and efficient opex, resulting from drivers such as changes in regulatory obligations or efficient capex/opex trade-offs, are then included in the opex forecast.

11 In respect of step changes, the AER observes, in the Expenditure Forecast Assessment Guideline (at pages 9-10):

> Our approach is to separately assess the prudence and efficiency of forecast cost increases or decreases associated with new regulatory obligations and capex/opex trade-offs. For capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa.
>
> …
>
> We will not allow step changes for any short-term cost to the DNSP of implementing efficiency improvements in expectation of being rewarded through expenditure incentive mechanisms such as the EBSS. We expect DNSPs to bear such costs and thereby make efficient trade-offs between bearing these costs and achieving future efficiencies.

12 The AER further observes (at pages 24-25):

> Step changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria. We will assess step changes in accordance with section 2.2 above. Step changes should not double count costs included in other elements of the opex forecast:
>
> • Step changes should not double count the costs of increased volume or scale compensated through the output measure in the rate of change.
>
> • 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.
>
> • Step changes should not double count the costs of discretionary changes in inputs. Efficient discretionary changes in inputs (not required to increase output) should normally have a net negative impact on expenditure.
>
> If it is efficient to substitute capex with opex, a step change may be included for these costs (capex/opex trade-offs).

13 When appropriate, however, the AER may assess some opex categories using other forecasting techniques, such as an efficient benchmark amount.[2]

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2 As above.

The EBSS and the AER's constituent decisions on its application

14 The EBSS is an incentive scheme that provides for a fair sharing between DNSPs and distribution network users of:

14.1 the efficiency gains derived from the opex of DNSPs for a RCP being less than; and

14.2 the efficiency losses derived from the opex of DNSPs for a RCP being more than,

the forecast opex accepted or substituted by the AER for that RCP.

15 The AER is required to develop and publish the EBSS, and may amend or replace the EBSS from time to time, in accordance with clause 6.5.8 of the NER.

16 The AER is required to make a constituent decision, in a distribution determination for a DNSP for a RCP, on each of:

16.1 how any applicable EBSS is to apply to the DNSP in that RCP (NER, clause 6.12.1(i)); and

16.2 the EBSS carryover amounts arising from the operation of any applicable EBSS in the preceding RCP (NER, clauses 6.4.3(a)(5) and (b)(5) and 6.12.1(j)).

Victorian DNSPs' 2021 - 2026 distribution determinations

AER decision on forecast insurance opex

17 In their regulatory proposals and/or revised regulatory proposals for the 2021 – 2026 RCP, each Victorian DNSP proposed a step change for insurance premiums, to reflect, in particular, forecast increases in bushfire insurance prices, and, thus, costs in that RCP due to global insurance market conditions. We have attached extracts of the relevant discussion from each Victorian DNSP's regulatory proposal and revised regulatory proposal, and the AER's draft and final decisions on each Victorian DNSP's distribution determinations for the 2021 – 2026 RCP, as Appendices 22 – 38.

18 Each Victorian DNSP provided the AER with a report from its insurance broker in support of its proposed step change. We have attached these reports as Appendices 39 – 42.

19 The AER ultimately included a step change for insurance premiums for each Victorian DNSP, as follows:

19.1 A $45.1 million ($2020/21) step change for AusNet;

19.2 A $28.2 million ($2020/21) step change for Jemena;

19.3 A $67.7 million ($2020/21) step change for Powercor; and

19.4 A $28.9 million ($2020/21) step change for United Energy.

20 However, the forecast increase in insurance pricing and premium costs in the 2021 – 2026 RCP did not eventuate to the extent contemplated in each Victorian DNSP's distribution determination, with the result that each Victorian DNSP will ultimately significantly underspend on insurance opex in 2021 – 2026 relative to the forecast insurance opex included in their 2021 – 2026 required revenue approved by the AER. We have provided, as Appendices 41 – 46, a comparison of each Victorian DNSP's actual insurance spend compared to their forecasts.

AER decision on application of the EBSS in the 2021 – 2026 RCP

21 In making its distribution determinations for the Victorian DNSPs for the 2021 – 2026 RCP, the AER decided to apply the *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers* dated November 2013 (**Version 2 EBSS**) to each of the Victorian DNSPs during that RCP.

22 The AER determined that, consistent with the Version 2 EBSS:

22.1 the length of the carryover period for the 2021 – 2026 RCP will be the same as the length of the DNSP's following RCP, noting that that RCP was expected to be five years commencing on 1 July 2026; and

22.2 in determining carryover amounts for the 2026 – 2031 RCP arising from the application of the EBSS in the 2021 – 2026 RCP, the AER will:

(a) exclude opex incurred on GSL payments and debt raising costs (and, for AusNet, innovation program costs), as these costs are not forecast on a single year revealed cost basis;

(b) adjust forecast opex to add (subtract) any approved revenue increments (decrements) made after the distribution determination for the RCP, such as approved pass through amounts or opex for contingent projects;

(c) adjust actual opex to remove demand management innovation allowance opex because it is not included in the opex forecast (but is often reported by DNSPs as part of their standard control services opex);

(d) adjust actual opex to add capitalised opex that has been excluded from the regulatory asset base;

(e) adjust forecast opex and actual opex for inflation;

(f) adjust actual opex to reverse any movements in provisions;

(g) adjust opex for any services that will not be classified as standard control services in the 2026 – 2031 RCP, to the extent these costs are not forecast using a single year revealed cost approach and excluding these costs between achieves the requirements of clause 6.5.8 of the NER.

23 A copy of the Version 2 EBSS and the accompanying Explanatory Statement dated November 2013 (**Version 2 EBSS Explanatory Statement**) are attached as Appendices 1 and 2. A copy of the accompanying EBSS Model can be found here: Efficiency benefit sharing scheme (EBSS) – November 2013 | Australian Energy Regulator (AER).

24 The Version 2 EBSS states that, in making a distribution determination for a RCP, actual opex in the final year of the preceding RCP is typically not known, with the result that the AER must estimate final year opex in calculating the estimated incremental efficiency gain for that year in a manner consistent with the estimate made when forecasting opex for the next RCP. As a result, the formulae for calculating the estimated incremental efficiency gain for the final year are specified in the Version 2 EBSS as follows:

$$I_{f,n} = \left(F_{f,n} - A^*_{f,n}\right) - \left(F_{f-1,n} - A_{f-1,n}\right)$$

Where A^*_f is the estimated actual opex for the final regulatory year, which will be calculated as:

$$A^*_{f,n} = F_{f,n} - \left(F_{b,n} - A_{b,n}\right) + \mathit{non\text{-}recurrent\ efficiency\ gain}_{b,n}$$

25 Similarly, the Version 2 EBSS states that, to ensure the carryover amount in the first year of the RCP is only for incremental efficiency gains made in that year, the AER will subtract any non-recurrent efficiency gain that was made back to base year opex when forecasting opex for that RCP. As a result, the formulae for calculating the incremental efficiency gain for the first year of the RCP are specified as follows:

$$I_{1,n} = (F_{1,n} - A_{1,n}) - [(F_{f,n-1} - A_{f,n-1}) - (F_{b,n-1} - A_{b,n-1})] - \textit{non-recurrent efficiency gain}_{b,n-1}$$

Where:

$I_{i,n}$ is the incremental efficiency gain in year i of period n

$F_{1,n}$ is forecast opex (subject to adjustments) in year 1 of period n

$A_{1,n}$ is actual opex (subject to adjustments) in year 1 of period n

$F_{f,n-1}$ is forecast opex (subject to adjustments) in the final year of period $n-1$

$A_{f,n-1}$ is actual opex (subject to adjustments) in the final year of period $n-1$

$F_{b,n-1}$ is forecast opex (subject to adjustments) in the base year of period $n-1$

$A_{b,n-1}$ is actual opex (subject to adjustments) in the base year of period $n-1$

$\textit{non-recurrent efficiency gain}_{b,n-1}$ is the adjustment made to base year opex used to forecast opex for period n to account for opex associated with one-off factors

f is the length of period n in years

b is the year of actual opex in period $n-1$ used as the basis to set forecast opex for period n.

26 Section 2.2 of the Version 2 EBSS Explanatory Statement, titled 'One-off factors in the base year', explains these aspects of the Version 2 EBSS in some detail. For your ease of reference, we reproduce section 2.2 of the Version 2 EBSS Explanatory Statement in Attachment 3 to this letter.

Victorian DNSPs' 2026 – 2031 regulatory proposals

27 The Victorian DNSPs (other than AusNet) did not propose a step change for insurance premiums in their regulatory proposals for the 2026 – 2031 RCP. The Victorian DNSPs followed the AER's established base-step-trend approach to forecasting their operating expenditure (described above).

28 As the Victorian DNSPs (other than AusNet) did not propose a step change for insurance premiums, their forecast insurance costs for the 2026 – 2031 RCP included in their proposed forecast total opex are equal to their actual insurance-related opex in the base year (being the 2024/25 regulatory year), adjusted to provide an estimate of opex for the final year of the RCP, and then trended forward to the 2026 – 2031 RCP by applying the rate of change.

29 AusNet proposed a $10.5 million ($2025/26) step change for insurance opex. As AusNet proposed a step change for insurance premiums, its forecast insurance costs for the 2026 – 2031 RCP included in its proposed forecast total opex are equal to its actual insurance-related opex in its base year (being the 2022/23 regulatory year), adjusted to provide an estimate of opex for the final year of the RCP, trended forward to the 2026 – 2031 RCP by applying the rate of change, and adding the requested step change amount.

30 Each of the Victorian DNSPs also proposed EBSS carryover amounts arising from the application of the Version 2 EBSS in the 2021 – 2026 RCP.

31 We have attached, as Appendices 6 - 10, relevant extracts from the Victorian DNSP's regulatory proposals for the 2026 – 2031 RCP.

AER Draft Decisions for the Victorian DNSPs for the 2026 – 2031 RCP

Draft decision on forecast insurance opex

32 In its Draft Decisions for each Victorian DNSP, in forecasting opex for the 2026 – 2031 RCP, the AER:

32.1 added a negative step change for insurance premiums, describing this as necessary to:

(a) (in respect of Powercor and United Energy) 'ensure that the overestimated insurance premiums included in forecast opex for the current 2021 – 2026 RCP don't impact forecast opex for the 2026 – 2031 RCP';[3] and

(b) (in respect of AusNet and Jemena) 'satisfy the opex criteria, and to treat the significant insurance premium underspends as non-recurrent efficiency gains';[4] and

32.2 included a 'base year non-recurrent efficiency gain', which is described as follows:

(a) (in respect of Powercor and United Energy) 'a base year non-recurrent efficiency gain in our alternative estimate relating to the insurance premiums step change we approved in the current regulatory control period. This adds the difference between the forecast of insurance premiums reflected in the approved step change and actual insurance premiums in the base year';[5] and

(b) (in respect of AusNet and Jemena) 'a non-recurrent efficiency gain, equal to the insurance premium underspend in the base year, to satisfy the opex criteria, and to share the significant insurance premium underspends with network users'.[6]

33 The AER also declined to approve AusNet's proposed insurance premium step change.

34 In its Draft Decisions for each Victorian DNSP, the AER noted that:[7]

> *The negative step change, calculated as the difference between the final year [insurance] premium allowance and the actual [insurance] premium, removes the expected over forecasting of insurance premiums in 2025 – 2025, thus ensuring this over forecasting doesn't continue into the 2026 – 2031 period. It then sets the non-recurrent efficiency gain in the base year equal to the insurance underspend in the base year. Together, this results in:*

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3 AER, *Attachment 3 – Operating Expenditure – Draft Decision – Powercor distribution determination 2026 – 2031,* 30 September 2025, page 35; AER, *Attachment 3 – Operating Expenditure – Draft Decision – United Energy distribution determination 2026 – 2031,* 30 September 2025, page 4.

4 AER, *Attachment 3 – Operating Expenditure – Draft Decision – AusNet distribution determination 2026 – 2031,* 30 September 2025, page 4; AER, *Attachment 3 – Operating Expenditure – Draft Decision – Jemena distribution determination 2026 – 2031,* 30 September 2025, page 4.

5 AER, *Attachment 3 – Operating Expenditure – Draft Decision – Powercor distribution determination 2026 – 2031,* 30 September 2025, page 10; AER, *Attachment 3 – Operating Expenditure – Draft Decision – United Energy distribution determination 2026 – 2031,* 30 September 2025, page 9.

6 AER, *Attachment 3 – Operating Expenditure – Draft Decision – Jemena distribution determination 2026 – 2031,* 30 September 2025, page 4; AER, *Attachment 3 – Operating Expenditure – Draft Decision – AusNet distribution determination 2026 – 2031,* 30 September 2025, page 4.

7 AER, *Attachment 3 – Operating Expenditure – Draft Decision – AusNet distribution determination 2026 – 2031,* 30 September 2025, page 3. We note that this statement may vary slightly across the Draft Decisions for each DNSP.

- *Forecast opex equal to that required by a prudent operator*

- *[AusNet/Jemena/Powercor/United Energy] returning all the 2021 – 2026 insurance premium underspends through EBSS decrements 6 years later (treating the underspends as non-recurrent efficiency gains).'*

Draft decision on carryover amounts for 2026 – 2031 arising from EBSS application in 2021 - 2026

35 In its Draft Decisions for each Victorian DNSP, in determining the EBSS carryover amounts for the 2026 – 2031 RCP arising from the application of the Version 2 EBSS in the 2021 – 2026 RCP, the AER makes an adjustment to reflect the non-recurrent efficiency gain adjustment to base year opex made in forecasting opex for the 2026 – 2031 RCP. In making its draft decision on this matter for AusNet, the AER observes that:[8]

> AusNet's proposed EBSS calculations did not include our approved 2018 base year non-recurrent efficiency gain, as required under our standard approach. Our draft decision alternative estimate has included the approved 2018 base year non-recurrent efficiency gain for the purpose of calculating the EBSS carryovers.

36 In asserting that its 'standard approach' requires the calculation of EBSS carryover amounts for 2026 – 2031 arising from the application of the EBSS in the 2021 – 2026 RCP to take account of its base year non-recurrent efficiency gain, the AER refers to page 22 of Attachment 8 to its draft decision for AusNet for the 2021 – 2026 RCP. Attachment 8 to this draft decision is only 14 pages in length (i.e. there is no page 22). The AER would appear to be referring to discussion of the making of a base year non-recurrent efficiency gain adjustment in respect of lease capitalisation costs in calculating the EBSS carryover amounts for the 2021 – 2026 RCP arising from the application of the EBSS in the preceding RCP commencing in 2016.

Scope of work

37 To assist the Victorian DNSPs in considering and responding to the AER's Draft Decisions, we are engaging you to prepare an independent expert report in respect of the AER's Draft Decisions.

38 You are instructed to prepare a report setting out an expert opinion on:

38.1 the approach the AER is purporting to have taken to determining the Victorian DNSPs' insurance opex in the Draft Decisions, including:

(a) the AER's reasoning and rationale for its purported approach; and

(b) the AER's stated objectives for its purported approach;

38.2 the approach the AER has actually taken to determining the Victorian DNSP's insurance opex in the Draft Decisions, including:

(a) whether the AER's actual approach is consistent with its purported approach as identified by you in response to 38.1; and

(b) to the extent the AER's actual approach is inconsistent with its purported approach, whether the AER's approach nonetheless is consistent with the AER's rationale, and achieves the AER's objectives, identified by you in response to 38.1(a) and (b);

38.3 the merits of the AER's reasoning, rationale and objectives as stated in the Draft Decisions and identified by you in response to 38.1.

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8 AER, *Attachment 5 – Efficiency Benefit Sharing Scheme – Draft Decision – AusNet distribution determination 2026 – 2031,* 30 September 2025, page 7. No analogous observation is made in the Draft Decisions for the other Victorian DNSPs.

Federal Court of Australia Expert Practice Note

39 As this matter may become litigious, we attach a copy of the Federal Court of Australia Expert Evidence Practice Note (**Practice Note**), which includes the Harmonised Expert Witness Code Conduct and Concurrent Expert Evidence Guidelines, as Attachment 4 to this letter.

40 Please carefully read the Practice Note and ensure that the report you provide in this matter complies with it. Further, in providing your report, you should:

40.1 include a curriculum vitae setting out full details of your relevant qualifications, experience and expertise;

40.2 include a copy of these instructions;

40.3 set out a list of all documents that you have relied upon in preparing your report;

40.4 expressly state all assumptions that you have made in preparing the report and the reasons for making those assumptions;

40.5 give reasons for each opinion that you express in the report;

40.6 qualify any opinion expressed in the report, if you consider your report may be incomplete or inaccurate without the qualification;

40.7 qualify any opinion expressed in the report, if you are unable to form a conclusive opinion because of insufficient research, insufficient information, or for any other reason;

40.8 at the end of the report, include a declaration in the following terms:

'*I have made all the inquiries that I believe are desirable and appropriate. No matters of significance that I regard as relevant have, to my knowledge, been withheld.*'

41 If you change your opinion after giving us the report in this matter, you must provide a supplementary report.

42 Please feel free to contact us to discuss. We look forward to working with you.

Yours sincerely

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Attachment 1 - Document index

#	Document
	Relevant AER Guidelines and Schemes
1.	AER efficiency benefit sharing scheme - November 2013
2.	AER explanatory statement - efficiency benefit sharing scheme - November 2013
3.	AER - Final decision - Expenditure Forecast Assessment Guidelines - Electricity Distribution - October 2024 (clean version)
4.	AER - Final decision and explanatory statement - Expenditure Forecast Assessment Guidelines - October 2024
5.	Expenditure Forecast Assessment Guideline - Explanatory Statement - FINAL
	DNSP Regulatory Proposals 2026 - 2031
6.	ASD - AusNet - EDPR 2026 - 2031 Regulatory Proposal -31 Jan 2025 - PUBLIC
7.	EDPR Insurance step change proposal - CONF
8.	JEN 2026-31 Proposal - 20250211
9.	Powercor Regulatory Proposal 2026-31 - Part B - Explanatory Statement - Jan2025
10.	United Energy Regulatory Proposal 2026-31 - Part B - Explanatory Statement - Jan2025
	Response to AER RFIs before release of Draft Decision 2026 - 2031
11.	JEN - IR011 - Initial Proposal Q & A Response - Historic and forecast opex - Stage 3 - 20250523 - Public
12.	Powercor - IR020 - opex over time and insurance - 20250505 - public
13.	United Energy - IR018 - opex over time and insurance - 20250505 - public
	AER Draft Decisions: 2026 - 2031
14.	AER - Attachment 3 - Operating expenditure - Draft decision - AusNet Services distribution determination 2026-31 - September 2025
15.	AER - Attachment 5 - Efficiency benefit sharing scheme - Draft decision - AusNet Services distribution determination 2026-31 - September 2025 (1)
16.	AER - Attachment 3 - Operating expenditure - Draft decision - Jemena distribution determination 2026-31 - September 2025
17.	AER - Attachment 5 - Efficiency benefit sharing scheme - Draft decision - Jemena distribution determination 2026-31 - September 2025

#	Document
18.	AER - Attachment 3 - Operating expenditure - Draft decision - Powercor distribution determination 2026-31 - September 2025 (1)
19.	AER - Attachment 5 - Efficiency benefit sharing scheme - Draft decision - Powercor distribution determination 2026-31 - September 2025 (1)
20.	AER - Attachment 3 - Operating expenditure - Draft decision - United Energy distribution determination 2026-31 September 2025
21.	AER - Attachment 5 - Efficiency benefit sharing scheme - Draft decision - United Energy distribution determination 2026-31 - September 2025
	DNSP Regulatory Proposals and AER Draft Decision: 2021 – 2026
22.	AusNet Services - EDPR 2022-26 Regulatory Proposal Part III - 31 January 2020_0
23.	AER - Draft decision - AusNet Services distribution determination 2021-26 - Attachment 6 - Operating expenditure - September 202
24.	Jemena - Attachment 06-05 - Operating Expenditure step changes - 31 January 2020
25.	AER - Draft decision - Jemena distribution determination 2021-26 - Attachment 6 - Operating expenditure
26.	Powercor - Regulatory Proposal - 31 January 2020
27.	AER - Draft decision - Powercor distribution determination 2021-26 - Attachment 6 - Operating expenditure - September 2020
28.	United Energy - Regulatory Proposal - 31 January 2020
29.	AER - Draft decision - United Energy distribution determination 2021-26 - Attachment 6 - Operating expenditure - September 2020
	DNSP Revised Regulatory Proposals and AER Final Decision: 2021 – 2026
30.	AusNet Services - Revised Regulatory Proposal - 2021-26 - December 2020
31.	AER - Final decision - AusNet Services distribution determination 2021–26 - Attachment 6 - Operating expenditure - April 2021
32.	Jemena - Revised Regulatory Proposal - 2021-26 - Att 05-01 Operating Expenditure - December 2020
33.	JEN - IR048 - Response to AER IR048 - 20200722 - Confidential
34.	AER - Final decision - Jemena distribution determination 2021–26 - Attachment 6 - Operating expenditure - April 2021
35.	PAL RRP BUS 9.05 - Insurance - Dec2020 - Confidential
36.	AER - Final decision - Powercor distribution determination 2021–26 - Attachment 6 - Operating expenditure - April 2021

#	Document
37.	United Energy - Revised Regulatory Proposal - 2021-26 - BUS 9.05 - Insurance - December 2020
38.	AER - Final decision - United Energy distribution determination 2021–26 - Attachment 6 - Operating expenditure - April 2021
	Insurance broker reports 2021 - 2026
39.	AusNet Services - Revised Regulatory Proposal - 2021-26 - AON - Appendix 10A - Australian bushfire impact study - December 2020
40.	JEN - AON Att 06-06 Insurance premium forecast report - 20200131 - Confidential
41.	JEN - Att 05-04 Jemena Insurance Report 2020 - 20201203 - Confidential
42.	Attachment A - IR048 - Jemena Liability Paper_update - 20200722 - Confidential
43.	PAL RRP ATT50 - Premiums forecasting report - Nov2020 - Confidential
	Insurance broker reports 2026 - 2031
44.	ASD - Lockton - Appendix 7D AusNet Insurance Premium Forecast Report - Final (29.01.2025) - 310125 - CONF
45.	Lockton, AusNet Services Pty Ltd, Addendum, 26 November 2025.
46.	Marsh, Victoria Power Networks Pty Ltd and United Energy Distribution Pty Ltd, 26 November 2025
47.	Lockton, Jemena Electricity Network (Vic) Ltd Insurance Premium Forecast, November 2025.

Attachment 2

1 This attachment sets out further information on behalf of each Victorian DNSP.

Powercor and United Energy

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Attachment 3 – Extract of section 2.2 of Version 2 EBSS Explanatory Statement

2.2 One-off factors in the base year

Where there are non-recurrent efficiency gains in the base year used to set the opex forecast, the opex forecast may not reflect the ongoing level of efficient opex by itself. However, the non-recurrent efficiency gains will lead to a positive EBSS carryover that will, in effect, compensate the NSP for the lower forecast. We have previously considered the revealed cost opex forecast, in combination with the EBSS carryover, will give NSPs their efficient opex requirement plus their share of efficiency gains or losses.

NSPs raised concerns that comparing their subsequent expenditure with their opex allowance could make them appear inefficient.

2.2.1 Approach

We consider there should be flexibility in the EBSS to enable revenue to be shifted from the EBSS carryover to the opex allowance to account for non-recurrent efficiency gains in the base year.

As a result, we have amended the EBSS to account for any adjustments made to base opex to remove the impacts of one-off factors.

This is given effect through an amendment to the equation we will use to calculate the incremental efficiency gain in the final year:

$$I_{f,n} = \left(F_{f,n} - A^{*}_{f,n}\right) - \left(F_{f-1,n} - A_{f-1,n}\right)$$

Where:

$I_{f,n}$ is the marginal efficiency gain in the final year of period n

$F_{f,n}$ is forecast opex (subject to adjustments) in the final year of period n

$A^{*}_{f,n}$ is estimated actual opex in the final year of period n

$F_{f-1,n}$ is forecast opex (subject to adjustments) in the penultimate year of period n

$A_{f-1,n}$ is actual opex (subject to adjustments) in the penultimate year of period n.

The estimated actual opex for the final regulatory year will be calculated as:

$$A^{*}_{f,n} = F_{f,n} - (F_{b,n} - A_{b,n}) + \textit{non-recurrent efficiency gain}_{b,n}$$

Where:

b is the year of actual opex in period n used as the basis to set forecast opex for period $n+1$

$\textit{non-recurrent efficiency gain}_{b,n}$ is the adjustment made to base year opex used to forecast opex for period $n+1$ to account for opex associated with one-off factors.

This also requires the following amendment to the calculation of the incremental efficiency gain for the first year of the following period:

$$I_{1,n} = (F_{1,n} - A_{1,n}) - [(F_{f,n-1} - A_{f,n-1}) - (F_{b,n-1} - A_{b,n-1})] - \textit{non-recurrent efficiency gain}_{b,n-1}$$

2.2.2 Reasons for approach

We have adopted this approach as a relatively simple and transparent method of taking account of efficiency gains occurring in the base year that will not persist into the future. It will minimise the rewards (penalties) for efficiency gains (losses) being carried forward by the opex forecast rather than the EBSS carryover payments.

Incenta Economic Consulting commented that, when testing the efficiency of a NSP's base year opex, it is important to ensure one-off factors do not impact the expenditure in the base year (and that adjustments are made if such one-off factors exist).[13] If base year expenditure is significantly lower than ongoing efficient opex, due to a one-off factor, then the opex forecast for the next period would be artificially low. In this case a NSP would be sufficiently compensated through the EBSS carryover, but the 'optics' could be misleading. That is, a NSP's actual expenditure could appear high compared against its regulatory allowance (not factoring in the EBSS carryover).

We note that there are alternative approaches to dealing with the issue of one-off factors in the base year. The forecasting approach in the Expenditure Assessment Forecast Guideline allows some discretion in choosing the base year. Where the base year is not reflective of ongoing costs we can choose another, more reflective base year, if one is available. In the event one-off factors do impact expenditure in the proposed base year, this would be our preferred approach.[14]

However, in the event a reflective base year is not available, we will adjust the base year to remove the impact of the one-off factor.[15] We will make the commensurate adjustment to the EBSS carryover amounts by calculating the incremental gain in the final year in accordance with the final year equation above. This would provide a similar revenue outcome to that which would be achieved if the actual base year (with the one-off factor) was used to set the opex forecast in combination with the unadjusted EBSS carryover amounts. This is highlighted in Box 2.2.

Box 2.2 Revenue impact of a base year one-off factor adjustment

Take the example of a NSP with an opex allowance of 100 dollars for each year of a five year regulatory control period. Its actual opex is as forecast in every year except the fourth year, when it spends 90 dollars due to a one-off factor. For simplicity assume there is no output, real price or productivity growth.

If we use the fourth year as the base year to forecast opex for the next regulatory control period, the forecast would be 90 dollars for each year of the next regulatory control period. Under the EBSS the NSP registers an incremental efficiency gain of 10 dollars in year four. The EBSS assumes the final or fifth year underspend is equal to the base year underspend. As a result, it registers no incremental gain/loss in year five. Thus the NSP would receive a 10 dollar carryover payment in the first four years of the next regulatory control period. Total opex revenue would be 450 dollars plus 40 dollars in EBSS carryovers.

However, say the one-off factor is identified and base opex is adjusted accordingly. Forecast opex would be 100 dollars for each year of the next regulatory control period. The EBSS registers an incremental efficiency gain of 10 dollars in year four. However, as with the adjustment to the base opex, we would also subtract the one-off factor adjustment from the year five incremental gain, which is now an incremental loss of 10 dollars. When the incremental gains/losses are carried forward the NSPs receives a single 10 dollar EBSS penalty in the final year of the next regulatory control period. Thus total opex revenue would be 500 dollars minus 10 dollars in EBSS carryovers. Total revenue is 490 dollars in both scenarios.

Attachment 4 - Federal Court of Australia Expert Practice Note

FEDERAL COURT OF AUSTRALIA

EXPERT EVIDENCE PRACTICE NOTE (GPN-EXPT)

General Practice Note

1. INTRODUCTION

1.1 This practice note, including the *Harmonised Expert Witness Code of Conduct* ("**Code**") (see **Annexure A**) and the *Concurrent Expert Evidence Guidelines* ("**Concurrent Evidence Guidelines**") (see **Annexure B**), applies to any proceeding involving the use of expert evidence and must be read together with:

(a) the Central Practice Note (CPN-1), which sets out the fundamental principles concerning the National Court Framework ("**NCF**") of the Federal Court and key principles of case management procedure;

(b) the Federal Court of Australia Act 1976 (Cth) ("**Federal Court Act**");

(c) the *Evidence Act 1995* (Cth) ("**Evidence Act**")**,** including Part 3.3 of the Evidence Act;

(d) Part 23 of the *Federal Court Rules 2011* (Cth) ("**Federal Court Rules**"); and

(e) where applicable, the Survey Evidence Practice Note (GPN-SURV).

1.2 This practice note takes effect from the date it is issued and, to the extent practicable, applies to proceedings whether filed before, or after, the date of issuing.

2. APPROACH TO EXPERT EVIDENCE

2.1 An expert witness may be retained to give opinion evidence in the proceeding, or, in certain circumstances, to express an opinion that may be relied upon in alternative dispute resolution procedures such as mediation or a conference of experts. In some circumstances an expert may be appointed as an independent adviser to the Court.

2.2 The purpose of the use of expert evidence in proceedings, often in relation to complex subject matter, is for the Court to receive the benefit of the objective and impartial assessment of an issue from a witness with specialised knowledge (based on training, study or experience - see generally s 79 of the Evidence Act).

2.3 However, the use or admissibility of expert evidence remains subject to the overriding requirements that:

(a) to be admissible in a proceeding, any such evidence must be relevant (s 56 of the Evidence Act); and

(b) even if relevant, any such evidence, may be refused to be admitted by the Court if its probative value is outweighed by other considerations such as the evidence being unfairly prejudicial, misleading or will result in an undue waste of time (s 135 of the Evidence Act).

2.4 An expert witness' opinion evidence may have little or no value unless the assumptions adopted by the expert (ie. the facts or grounds relied upon) and his or her reasoning are expressly stated in any written report or oral evidence given.

2.5 The Court will ensure that, in the interests of justice, parties are given a reasonable opportunity to adduce and test relevant expert opinion evidence. However, the Court expects parties and any legal representatives acting on their behalf, when dealing with expert witnesses and expert evidence, to at all times comply with their duties associated with the overarching purpose in the Federal Court Act (see ss 37M and 37N).

3. INTERACTION WITH EXPERT WITNESSES

3.1 Parties and their legal representatives should never view an expert witness retained (or partly retained) by them as that party's advocate or “hired gun”. Equally, they should never attempt to pressure or influence an expert into conforming his or her views with the party's interests.

3.2 A party or legal representative should be cautious not to have inappropriate communications when retaining or instructing an independent expert, or assisting an independent expert in the preparation of his or her evidence. However, it is important to note that there is no principle of law or practice and there is nothing in this practice note that obliges a party to embark on the costly task of engaging a “consulting expert” in order to avoid “contamination” of the expert who will give evidence. Indeed the Court would generally discourage such costly duplication.

3.3 Any witness retained by a party for the purpose of preparing a report or giving evidence in a proceeding as to an opinion held by the witness that is wholly or substantially based in the specialised knowledge of the witness[9] should, at the earliest opportunity, be provided with:

[9] Such a witness includes a “Court expert” as defined in r 23.01 of the Federal Court Rules. For the definition of "expert", "expert evidence" and "expert report" see the Dictionary, in Schedule 1 of the Federal Court Rules.

(a) a copy of this practice note, including the Code (see Annexure A); and

(b) all relevant information (whether helpful or harmful to that party's case) so as to enable the expert to prepare a report of a truly independent nature.

3.4 Any questions or assumptions provided to an expert should be provided in an unbiased manner and in such a way that the expert is not confined to addressing selective, irrelevant or immaterial issues.

4. ROLE AND DUTIES OF THE EXPERT WITNESS

4.1 The role of the expert witness is to provide relevant and impartial evidence in his or her area of expertise. An expert should never mislead the Court or become an advocate for the cause of the party that has retained the expert.

4.2 It should be emphasised that there is nothing inherently wrong with experts disagreeing or failing to reach the same conclusion. The Court will, with the assistance of the evidence of the experts, reach its own conclusion.

4.3 However, experts should willingly be prepared to change their opinion or make concessions when it is necessary or appropriate to do so, even if doing so would be contrary to any previously held or expressed view of that expert.

1 Harmonised Expert Witness Code of Conduct

4.4 Every expert witness giving evidence in this Court must read the *Harmonised Expert Witness Code of Conduct* (attached in Annexure A) and agree to be bound by it.

4.5 The Code is not intended to address all aspects of an expert witness' duties, but is intended to facilitate the admission of opinion evidence, and to assist experts to understand in general terms what the Court expects of them. Additionally, it is expected that compliance with the Code will assist individual expert witnesses to avoid criticism (rightly or wrongly) that they lack objectivity or are partisan.

5. CONTENTS OF AN EXPERT'S REPORT AND RELATED MATERIAL

5.1 The contents of an expert's report must conform with the requirements set out in the Code (including clauses 3 to 5 of the Code).

5.2 In addition, the contents of such a report must also comply with r 23.13 of the Federal Court Rules. Given that the requirements of that rule significantly overlap with the requirements in the Code, an expert, unless otherwise directed by the Court, will be taken to have complied with the requirements of r 23.13 if that expert has complied with the requirements in the Code and has complied with the additional following requirements. The expert shall:

(a) acknowledge in the report that:

(i) the expert has read and complied with this practice note and agrees to be bound by it; and

(ii) the expert's opinions are based wholly or substantially on specialised knowledge arising from the expert's training, study or experience;

(b) identify in the report the questions that the expert was asked to address;

(c) sign the report and attach or exhibit to it copies of:

(i) documents that record any instructions given to the expert; and

(ii) documents and other materials that the expert has been instructed to consider.

5.3 Where an expert's report refers to photographs, plans, calculations, analyses, measurements, survey reports or other extrinsic matter, these must be provided to the other parties at the same time as the expert's report.

6. CASE MANAGEMENT CONSIDERATIONS

6.1 Parties intending to rely on expert evidence at trial are expected to consider between them and inform the Court at the earliest opportunity of their views on the following:

(a) whether a party should adduce evidence from more than one expert in any single discipline;

(b) whether a common expert is appropriate for all or any part of the evidence;

(c) the nature and extent of expert reports, including any in reply;

(d) the identity of each expert witness that a party intends to call, their area(s) of expertise and availability during the proposed hearing;

(e) the issues that it is proposed each expert will address;

(f) the arrangements for a conference of experts to prepare a joint-report (see Part 7 of this practice note);

(g) whether the evidence is to be given concurrently and, if so, how (see Part 8 of this practice note); and

(h) whether any of the evidence in chief can be given orally.

6.2 It will often be desirable, before any expert is retained, for the parties to attempt to agree on the question or questions proposed to be the subject of expert evidence as well as the relevant facts and assumptions. The Court may make orders to that effect where it considers it appropriate to do so.

7. CONFERENCE OF EXPERTS AND JOINT-REPORT

7.1 Parties, their legal representatives and experts should be familiar with aspects of the Code relating to conferences of experts and joint-reports (see clauses 6 and 7 of the Code attached in Annexure A).

7.2 In order to facilitate the proper understanding of issues arising in expert evidence and to manage expert evidence in accordance with the overarching purpose, the Court may require experts who are to give evidence or who have produced reports to meet for the purpose of identifying and addressing the issues not agreed between them with a view to reaching agreement where this is possible ("**conference of experts**"). In an appropriate case, the Court may appoint a registrar of the Court or some other suitably qualified person ("**Conference Facilitator**") to act as a facilitator at the conference of experts.

7.3 It is expected that where expert evidence may be relied on in any proceeding, at the earliest opportunity, parties will discuss and then inform the Court whether a conference of experts and/or a joint-report by the experts may be desirable to assist with or simplify the giving of expert evidence in the proceeding. The parties should discuss the necessary arrangements for any conference and/or joint-report. The arrangements discussed between the parties should address:

(a) who should prepare any joint-report;

(b) whether a list of issues is needed to assist the experts in the conference and, if so, whether the Court, the parties o r the experts should assist in preparing such a list;

(c) **t**he agenda for the conference of experts; and

(d) arrangements for the provision, to the parties and the Court, of any joint-report or any other report as to the outcomes of the conference ("**conference report**").

2 Conference of Experts

7.4 The purpose of the conference of experts is for the experts to have a comprehensive discussion of issues relating to their field of expertise, with a view to identifying matters and issues in a proceeding about which the experts agree, partly agree or disagree and why. For this reason the conference is attended only by the experts and any Conference Facilitator. Unless the Court orders otherwise, the parties' lawyers will not attend the conference but will be provided with a copy of any conference report.

7.5 The Court may order that a conference of experts occur in a variety of circumstances, depending on the views of the judge and the parties and the needs of the case, including:

(a) while a case is in mediation. When this occurs the Court may also order that the outcome of the conference or any document disclosing or summarising the experts' opinions be confidential to the parties while the mediation is occurring;

(b) before the experts have reached a final opinion on a relevant question or the facts involved in a case. When this occurs the Court may order that the parties exchange draft expert reports and that a conference report be prepared for the use of the experts in finalising their reports;

(c) after the experts' reports have been provided to the Court but before the hearing of the experts' evidence. When this occurs the Court may also order that a conference report be prepared (jointly or otherwise) to ensure the efficient hearing of the experts' evidence.

7.6 Subject to any other order or direction of the Court, the parties and their lawyers must not involve themselves in the conference of experts process. In particular, they must not seek to encourage an expert not to agree with another expert or otherwise seek to influence the outcome of the conference of experts. The experts should raise any queries they may have in relation to the process with the Conference Facilitator (if one has been appointed) or in accordance with a protocol agreed between the lawyers prior to the conference of experts taking place (if no Conference Facilitator has been appointed).

7.7 Any list of issues prepared for the consideration of the experts as part of the conference of experts process should be prepared using non-tendentious language.

7.8 The timing and location of the conference of experts will be decided by the judge or a registrar who will take into account the location and availability of the experts and the Court's case management timetable. The conference may take place at the Court and will usually be conducted in-person. However, if not considered a hindrance to the process, the conference may also be conducted with the assistance of visual or audio technology (such as via the internet, video link and/or by telephone).

7.9 Experts should prepare for a conference of experts by ensuring that they are familiar with all of the material upon which they base their opinions. Where expert reports in draft or final form have been exchanged prior to the conference, experts should attend the conference familiar with the reports of the other experts. Prior to the conference, experts should also consider where they believe the differences of opinion lie between them and what processes and discussions may assist to identify and refine those areas of difference.

3 Joint-report

7.10 At the conclusion of the conference of experts, unless the Court considers it unnecessary to do so, it is expected that the experts will have narrowed the issues in respect of which they agree, partly agree or disagree in a joint-report. The joint-report should be clear, plain and concise and should summarise the views of the experts on the identified issues, including a succinct explanation for any differences of opinion, and otherwise be structured in the manner requested by the judge or registrar.

7.11 In some cases (and most particularly in some native title cases), depending on the nature, volume and complexity of the expert evidence a judge may direct a registrar to draft part, or all, of a conference report. If so, the registrar will usually provide the draft conference report to the relevant experts and seek their confirmation that the conference report accurately reflects the opinions of the experts expressed at the conference. Once that confirmation has been received the registrar will finalise the conference report and provide it to the intended recipient(s).

8. CONCURRENT EXPERT EVIDENCE

8.1 The Court may determine that it is appropriate, depending on the nature of the expert evidence and the proceeding generally, for experts to give some or all of their evidence concurrently at the final (or other) hearing.

8.2 Parties should familiarise themselves with the *Concurrent Expert Evidence Guidelines* (attached in Annexure B). The Concurrent Evidence Guidelines are not intended to be exhaustive but indicate the circumstances when the Court might consider it appropriate for concurrent expert evidence to take place, outline how that process may be undertaken, and assist experts to understand in general terms what the Court expects of them.

8.3 If an order is made for concurrent expert evidence to be given at a hearing, any expert to give such evidence should be provided with the Concurrent Evidence Guidelines well in advance of the hearing and should be familiar with those guidelines before giving evidence.

9. FURTHER PRACTICE INFORMATION AND RESOURCES

9.1 Further information regarding Expert Evidence and Expert Witnesses is available on the Court's website.

9.2 Further information to assist litigants, including a range of helpful guides, is also available on the Court's website. This information may be particularly helpful for litigants who are representing themselves.

J L B ALLSOP
Chief Justice
25 October 2016

4 Annexure A

1 HARMONISED EXPERT WITNESS CODE OF CONDUCT[10]

1 APPLICATION OF CODE

1. This Code of Conduct applies to any expert witness engaged or appointed:

   (a) to provide an expert's report for use as evidence in proceedings or proposed proceedings; or

   (b) to give opinion evidence in proceedings or proposed proceedings.

2 GENERAL DUTIES TO THE COURT

2. An expert witness is not an advocate for a party and has a paramount duty, overriding any duty to the party to the proceedings or other person retaining the expert witness, to assist the Court impartially on matters relevant to the area of expertise of the witness.

3 CONTENT OF REPORT

3. Every report prepared by an expert witness for use in Court shall clearly state the opinion or opinions of the expert and shall state, specify or provide:

   (a) the name and address of the expert;

   (b) an acknowledgment that the expert has read this code and agrees to be bound by it;

   (c) the qualifications of the expert to prepare the report;

   (d) the assumptions and material facts on which each opinion expressed in the report is based [a letter of instructions may be annexed];

   (e) the reasons for and any literature or other materials utilised in support of such opinion;

   (f) (if applicable) that a particular question, issue or matter falls outside the expert's field of expertise;

   (g) any examinations, tests or other investigations on which the expert has relied, identifying the person who carried them out and that person's qualifications;

   (h) the extent to which any opinion which the expert has expressed involves the acceptance of another person's opinion, the identification of that other person and the opinion expressed by that other person;

[10] Approved by the Council of Chief Justices' Rules Harmonisation Committee

(i) a declaration that the expert has made all the inquiries which the expert believes are desirable and appropriate (save for any matters identified explicitly in the report), and that no matters of significance which the expert regards as relevant have, to the knowledge of the expert, been withheld from the Court;

(j) any qualifications on an opinion expressed in the report without which the report is or may be incomplete or inaccurate;

(k) whether any opinion expressed in the report is not a concluded opinion because of insufficient research or insufficient data or for any other reason; and

(l) where the report is lengthy or complex, a brief summary of the report at the beginning of the report.

4 SUPPLEMENTARY REPORT FOLLOWING CHANGE OF OPINION

4. Where an expert witness has provided to a party (or that party's legal representative) a report for use in Court, and the expert thereafter changes his or her opinion on a material matter, the expert shall forthwith provide to the party (or that party's legal representative) a supplementary report which shall state, specify or provide the information referred to in paragraphs (a), (d), (e), (g), (h), (i), (j), (k) and (I) of clause 3 of this code and, if applicable, paragraph (f) of that clause.

5. In any subsequent report (whether prepared in accordance with clause 4 or not) the expert may refer to material contained in the earlier report without repeating it.

5 DUTY TO COMPLY WITH THE COURT'S DIRECTIONS

6. If directed to do so by the Court, an expert witness shall:

(a) confer with any other expert witness;

(b) provide the Court with a joint-report specifying (as the case requires) matters agreed and matters not agreed and the reasons for the experts not agreeing; and

(c) abide in a timely way by any direction of the Court.

6 CONFERENCE OF EXPERTS

7. Each expert witness shall:

(a) exercise his or her independent judgment in relation to every conference in which the expert participates pursuant to a direction of the Court and in relation to each report thereafter provided, and shall not act on any instruction or request to withhold or avoid agreement; and

(b) endeavour to reach agreement with the other expert witness (or witnesses) on any issue in dispute between them, or failing agreement, endeavour to identify and clarify the basis of disagreement on the issues which are in dispute.

ANNEXURE B

CONCURRENT EXPERT EVIDENCE GUIDELINES

1 APPLICATION OF THE COURT'S GUIDELINES

1. The Court's Concurrent Expert Evidence Guidelines ("**Concurrent Evidence Guidelines**") are intended to inform parties, practitioners and experts of the Court's general approach to concurrent expert evidence, the circumstances in which the Court might consider expert witnesses giving evidence concurrently and, if so, the procedures by which their evidence may be taken.

2 OBJECTIVES OF CONCURRENT EXPERT EVIDENCE TECHNIQUE

2. The use of concurrent evidence for the giving of expert evidence at hearings as a case management technique[11] will be utilised by the Court in appropriate circumstances (see r 23.15 of the *Federal Court Rules 2011* (Cth)). Not all cases will suit the process. For instance, in some patent cases, where the entire case revolves around conflicts within fields of expertise, concurrent evidence may not assist a judge. However, patent cases should not be excluded from concurrent expert evidence processes.

3. In many cases the use of concurrent expert evidence is a technique that can reduce the partisan or confrontational nature of conventional hearing processes and minimises the risk that experts become "opposing experts" rather than independent experts assisting the Court. It can elicit more precise and accurate expert evidence with greater input and assistance from the experts themselves.

4. When properly and flexibly applied, with efficiency and discipline during the hearing process, the technique may also allow the experts to more effectively focus on the critical points of disagreement between them, identify or resolve those issues more quickly, and narrow the issues in dispute. This can also allow for the key evidence to be given at the same time (rather than being spread across many days of hearing); permit the judge to assess an expert more readily, whilst allowing each party a genuine opportunity to put and test expert evidence. This can reduce the chance of the experts, lawyers and the judge misunderstanding the opinions being expressed by the experts.

5. It is essential that such a process has the full cooperation and support of all of the individuals involved, including the experts and counsel involved in the questioning process. Without that cooperation and support the process may fail in its objectives

[11] Also known as the "hot tub" or as "expert panels".

and even hinder the case management process.

3 CASE MANAGEMENT

6. Parties should expect that, the Court will give careful consideration to whether concurrent evidence is appropriate in circumstances where there is more than one expert witness having the same expertise who is to give evidence on the same or related topics. Whether experts should give evidence concurrently is a matter for the Court, and will depend on the circumstances of each individual case, including the character of the proceeding, the nature of the expert evidence, and the views of the parties.

7. Although this consideration may take place at any time, including the commencement of the hearing, if not raised earlier, parties should raise the issue of concurrent evidence at the first appropriate case management hearing, and no later than any pre-trial case management hearing, so that orders can be made in advance, if necessary. To that end, prior to the hearing at which expert evidence may be given concurrently, parties and their lawyers should confer and give general consideration as to:

   (a) the agenda;

   (b) the order and manner in which questions will be asked; and

   (c) whether cross-examination will take place within the context of the concurrent evidence or after its conclusion.

8. At the same time, and before any hearing date is fixed, the identity of all experts proposed to be called and their areas of expertise is to be notified to the Court by all parties.

9. The lack of any concurrent evidence orders does not mean that the Court will not consider using concurrent evidence without prior notice to the parties, if appropriate.

4 CONFERENCE OF EXPERTS & JOINT-REPORT OR LIST OF ISSUES

10. The process of giving concurrent evidence at hearings may be assisted by the preparation of a joint-report or list of issues prepared as part of a conference of experts.

11. Parties should expect that, where concurrent evidence is appropriate, the Court may make orders requiring a conference of experts to take place or for documents such as a joint-report to be prepared to facilitate the concurrent expert evidence process at a hearing (see Part 7 of the Expert Evidence Practice Note).

5 PROCEDURE AT HEARING

12. Concurrent expert evidence may be taken at any convenient time during the hearing, although it will often occur at the conclusion of both parties' lay evidence.

13. At the hearing itself, the way in which concurrent expert evidence is taken must be applied flexibly and having regard to the characteristics of the case and the nature of the evidence to be given.

14. Without intending to be prescriptive of the procedure, parties should expect that, when evidence is given by experts in concurrent session:

(a) the judge will explain to the experts the procedure that will be followed and that the nature of the process may be different to their previous experiences of giving expert evidence;

(b) the experts will be grouped and called to give evidence together in their respective fields of expertise;

(c) the experts will take the oath or affirmation together, as appropriate;

(d) the experts will sit together with convenient access to their materials for their ease of reference, either in the witness box or in some other location in the courtroom, including (if necessary) at the bar table;

(e) each expert may be given the opportunity to provide a summary overview of their current opinions and explain what they consider to be the principal issues of disagreement between the experts, as they see them, in their own words;

(f) the judge will guide the process by which evidence is given, including, where appropriate:

(i) using any joint-report or list of issues as a guide for all the experts to be asked questions by the judge and counsel, about each issue on an issue-by-issue basis;

(ii) ensuring that each expert is given an adequate opportunity to deal with each issue and the exposition given by other experts including, where considered appropriate, each expert asking questions of other experts or supplementing the evidence given by other experts;

(iii) inviting legal representatives to identify the topics upon which they will cross-examine;

(iv) ensuring that legal representatives have an adequate opportunity to ask all experts questions about each issue. Legal representatives may also seek responses or contributions from one or more experts in response to the evidence given by a different expert; and

(v) allowing the experts an opportunity to summarise their views at the end of the process where opinions may have been changed or clarifications are needed.

15. The fact that the experts may have been provided with a list of issues for consideration does not confine the scope of any cross-examination of any expert. The process of cross-examination remains subject to the overall control of the judge.

16. The concurrent session should allow for a sensible and orderly series of exchanges between expert and expert, and between expert and lawyer. Where appropriate, the judge may allow for more traditional cross-examination to be pursued by a legal representative on a particular issue exclusively with one expert. Where that occurs, other experts may be asked to comment on the evidence given.

17. Where any issue involves only one expert, the party wishing to ask questions about that issue should let the judge know in advance so that consideration can be given to whether arrangements should be made for that issue to be dealt with after the completion of the concurrent session. Otherwise, as far as practicable, questions (including in the form of cross-examination) will usually be dealt with in the concurrent session.

18. Throughout the concurrent evidence process the judge will ensure that the process is fair and effective (for the parties and the experts), balanced (including not permitting one expert to overwhelm or overshadow any other expert), and does not become a protracted or inefficient process.

Annexure B – Curriculum vitae

Brendan Quach

Senior Economist

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Overview

Brendan has worked as a consulting economist, specialising in network economics and finance in Australia, New Zealand and Asia Pacific region. Over the last 24 years Brendan has advised clients on the application of regulatory principles to airports, ports, telecommunications electricity transmission and distribution networks, water networks and gas pipelines. He has provided advice on application of the building block approach, incentive mechanisms, operating and capital allowances, financing, pricing and asset valuation to businesses, regulators and governments.

Brendan is a specialist in the cost of capital for use in regulatory price reviews and contract arbitrations. He has authored reports on all aspects of the cost of capital including equity estimation techniques, the impact of tax imputation credits, and estimating benchmark debt costs.

Qualifications

1991-1995 **Australian National University**
Bachelor of Economics
(High Second Class Honours)

1991-1997 **Australian National University**
Bachelor of Laws

Career Details

2014- **HoustonKemp Economists**
Senior Economist, Sydney, Australia

2001-2014 **NERA Economic Consulting**
Senior Consultant, Sydney, Australia

1998-1999 **Australian Chamber of Commerce and Industry**

Project Experience

Finance

2025	**Wellington International Airport** **Commerce Commission's assessment of credit rating and leverage** Co-authored an independent expert report assessing the New Zealand Commerce Commission's conclusions on Wellington Airport's 2024 to 2029 price setting event. The report critiqued the Commission's approach for evaluating Wellington Airport's credit rating and its methodology for calculating the actual leverage of a firm that was not publicly traded.
2025	**Confidential client** **Methodology for updating estimates of the WACC** Co-authored an expert report that provided internal advice explaining the methodology that the Supreme Court of Western Australia accepted for calculating the weighted average cost of capital in its *quantum meruit* judgment in *Perth Airport Pty Ltd v Qantas*.
2025	**Confidential client** **Approaches for calculating the benchmark weighted average cost of capital for an airport** Advised a confidential Australian airport on the range of benchmark WACC estimates derived using multiple approaches by Australian regulators, as well as the advantages and disadvantages associated with each approach. The project also involved assisting the client with responding to alternative WACC estimates provided by customers.
2025	**Airservices Australia** **Weighted average cost of capital for a benchmark air navigation service provider** Co-authored an independent expert report the calculated the benchmark weighted average cost of capital to be used as an input to Airservices Australia's building block model. The report used the ACCC's WACC methodology when calculating market-wide WACC parameters, while using first principles to identify the appropriate comparator sample to be used to calculate industry-specific WACC parameters. The project also involved multiple meetings and presentations with Airservices management, industry stakeholders and the ACCC.
2025	**Confidential client** **Judicial review** Assisted a confidential client with a judicial review regarding the benchmark weighted average cost of capital.
2025	**Fiji Airports** **Cost allocation and pricing model** Brendan led a team that developed a cost allocation methodology and constructed a building block model to calculate prices for Fiji Airports' aeronautical services for 19 airports and six services over the 2026-30 regulatory pricing period.

2024	**Fiji Airports** **Weighted average cost of capital for a benchmark Fijian airport** Co-authored an expert report that calculated the weighted average cost of capital for aeronautical and air navigation services at a benchmark Fijian airport. This weighted average cost of capital estimate was subsequently used as an input to the building block model that Fiji Airports used to determine service charges. The project also involved presentations to Fiji Airports management and to the Fijian Competition and Consumer Commission.
2024	**Confidential client, Australia** **Benchmark WACC for an airport with a large capital program** Lead a team that estimated the benchmark rate of return to be applied to particular aeronautical services at two major Australian capital city airports, drawing extensively on precedent from decisions by regulators in Australia, New Zealand, United Kingdom and Ireland. This work included developing a rate of return strategy for negotiations, reasonable WACC range, advice on regulatory and financial market developments and presenting to the Board.
2024	**Confidential client, Australia** **Updating the WACC** Estimated the benchmark WACC for an Australian airport, taking into account precedent from the Supreme Court of Western Australia, the Australian Energy Regulator and the New Zealand Commerce Commission. The advice included sensitivity analysis for scenarios under different assumptions.
2023-24	**Maurice Blackburn** **Car loan interest rates** Authored three expert reports estimating the average market rate for car loans in the context of three class actions against Westpac, ANZ and Macquarie Bank. Testified before the Supreme Court of Victoria as an expert witness in the Flex commissions class actions – Fox & Anor v Westpac Banking Corporation (ECI 2020 02946) and Nathan v Macquarie (S ECI 2020 03924).
2024	**Ausgrid** **Regulatory advice on the Hunter Central Cost REZ** Providing regulatory support in relation to Ausgrid's bid to be the network operator for the Hunter Central Cost REZ. Advice covers regulatory modelling, development of expenditure forecasts and assessment and quantification of project risk.
2024	**Confidential client** **Rate of return for state capital and regional airport** Led a team that estimated a defendable rate of return for a state capital airport and a regional airport. Considered all components of the rate of return including the impact of COVID, the selection of a sample of comparable listed airports, and the WACC methodology.
2024	**OMERS Infrastructure Management** **Rate of return and regulatory environment for Australian airports** Led a team that produces a vendor due diligence report on the cost of capital and regulatory context apply to a number of Australian airports.

2024	**New Zealand Airports Association** **Advice on the rate of return** Provided NZ Airports with advice on errors contained in the NZCC's 2023 Input Methodologies final decision. Our advice culminated in a Joint Expert report on errors in NZCC's final decision.
2023-24	**Marinus Link Propriety** **Quantification of project risks for HVDC interconnector** Advised Marinus Link on the identification and quantification of project risks that can be con be recovered from customers.
2023-24	**Wellington International Airport Ltd** **Advice of the rate of return** Provided Wellington International Airport Limited (WIAL) with assistance in the development of both a recommended WACC and their approach to setting a target return for Price Setting event 5 and included the provision of an expert report. Our assistance extending to advice to WIAL on the development of the Commerce Commission's 2023 Input Methodologies.
2023	**Queensland Rail, Weighted Average Cost of Capital for the West Moreton system** Brendan provided advice on the appropriate weighted average cost of capital that should be adopted by Queensland Rail for the West Moreton system.
2023	**Herbert Smith Freehills, Port of Melbourne** **Review of benchmarking gearing** Assisted HSF on providing legal advice to the Port of Melbourne (PoM) on responding the Essential Service Commission (ESC) concerns with the benchmark gearing ratio used to calculate the WACC apply to a multi-year regulatory period, consistent with the Pricing Order.
2022	**Herbert Smith Freehills, Port of Melbourne** **Implications of a multi-year pricing period** Expert report on potential approaches that Port of Melbourne (PoM) can adopt for transitioning the weighted average cost of capital (WACC) to a multi-year regulatory period, consistent with the Pricing Order.
2022	**Transport Asset Holding Entity, Development of 30 year financial model** Development of a financial model to support the development of financial projections across TAHE's rail infrastructure networks, and support access price setting.
2022	**Herbert Smith Freehills/ Port of Melbourne** **The cost of capital for a benchmark container port** Brendan co-authored an independent expert report on the cost of capital for a benchmark container port, consistent with the consistent with the Pricing Order made under section 49A of the *Port Management Act 1995* (Vic).
2022	**DLA Piper** **The cost of capital for a benchmark airport** Brendan led a team that estimated the cost of capital for number of Australian airports consistent with the Western Australian Supreme Court decision *Perth Airport Pty Ltd v Qantas Airways Ltd [No 2]* [2021] WASC 342.

2021	**Johnson Winter & Slattery/Port of Melbourne** **Cross checks to assess the allowance sought by the Port to recover a return on its capital base** Brendan co-authored an expert report that assessed the proposed cross checks undertaken by the Essential Services Commission to the Port's allowance to recover a return on its capital base. The report also identified other cross checks that were appropriate to assess the Port's proposed rate of return. The report also evaluated whether the Port's 2021-22 tariff compliance statement satisfied the identified appropriate cross checks.
2021	**Dalrymple Bay Infrastructure** **Appropriate rate of return for an export coal terminal** Brendan advised DBI on the appropriate rate of return for an export coal terminal in the context of its new light handed access framework for the DBCT service under the Queensland Competition Act.
2020	**Australian Energy Markets Authority** **Interest rate to applied to deferred network charges** Brendan provided advice to the AEMC on the appropriate interest rate that should be applied to the deferred network charges. This advice in in the context of the AEMC's assessment of the rule change request submitted by the Australian Energy Regulator (AER) to amend the National Electricity Rules (NER) to allow retailers to defer the payment of network charges of customers subject to COVID-19 customer arrangements.
2019-20	**DLA Piper** **Commercial arbitration regarding a National Energy Market (NEM) transmission asset** Assisted with the development of an expert report on appropriate discount rate to determine damages in relation to a commercial arbitration. Further advice was provided on the modelling used to calculate damages.
2019	**Hobart International Airport** **Review of aeronautical regulatory model and WACC** Brendan produced two reports for Hobart Airport. The first report assessed the economic and financial logic of the model used to estimate the aeronautical services charges necessary to recover forecasts costs over the 2020/21 to 2024/25 period. This review included a review of the weighted average cost of capital (WACC) assumptions in the model. Brendan provided Hobart Airport with a subsequent report that estimated a defensible return on assets providing aeronautical services.

2019	**Queensland Rail** **Revision of the WACC to be applied in the 2020 access undertaking** Brendan led a team that provided strategic advice to Queensland Rail on the rate for return. This advice led to the development of two expert reports. The first report examined the use of regulator judgement and discretion in both the choice of how to estimate the rate of return and how they assess the compensation for benchmark debt and equity risk. The report encompassed the methodologies of the ACCC, Independent Pricing and Regulatory Tribunal (IPART) and the ERA and highlighted that regulatory discretion in calculating the rate of return led to significant differences for similar regulated entities operating in different jurisdictions The second report presented empirical analysis of the different approaches to inflation forecasting considered by the QCA, ie, the RBA inflation target method, the RBA forecasting method and the indexed bond method. We concluded that the approach adopted by the QCA (the RBA forecasting method) does not produce superior inflation forecasts, and recommend that the QCA uses an average of the RBA forecasting method and indexed bond method.
2019	**Private infrastructure investor group** **Impact on investment of lowering the Equity Risk Premium** Brendan led a team that assessed investment outcomes across regulated Australian gas and electricity networks since 2006 and the impact of changes the ERP provided by Australian regulators. Our analysis observed a reduction in network capex compared to regulatory forecasts, concurrent with reductions in the allowed ERP.
2019	**DLA Piper/Townsville Airport** **Review of financial model supporting aeronautical pricing** Brendan undertook a review the financial model that will be used to support the proposed aeronautical prices at Townsville airport. This analysis assessed the economic and financial logic of the model with respect to asset values, revenues and prices.
2018-19	**Wellington International Airport Ltd** **Advice of the rate of return** Provided Wellington International Airport Limited (WIAL) with assistance in the development of both a recommended WACC and their approach to setting a target return to be applied in a revised pricing proposal for the provision of terminal and airfield services at WIAL. Our assistance included the provision of an expert report on WIAL's WACC and target rate of return.
2018	**NT Airport** **Strategic advice on the cost of capital for a regional airport** Brendan provided advice on the cost of capital for a benchmark airport service provider in the circumstances of the Alice Springs Airport. The advice focused on regulatory precedent on the WACC for airports in Australia and New Zealand as well as the approaches to estimating the rate of return applied by Australasian regulators.
2018	**ATCO Gas** **Strategic advice on the cost of capital of a gas network** Brendan provided strategic advice on the appropriate cost of capital and financial models for a benchmark gas distribution system.

2017	**ESCOSA** **Cost of capital for a benchmark water business** Provided advice to the Commission on the implications of a move to a long-term cost of equity allowance for a benchmark water utility. This advice considered the implications of this change to customer prices, the volatility of regulated revenues, and the impact on incentives for efficient investment by a regulated business.
2017	**Western Power** **Refinements to the ERA's approach to the MRP** Brendan co-authored an expert report that assesses the approach of Economic Regulation Authority to setting a prevailing market risk premium (MRP) and suggesting a number of refinements. We review both the calculation of the long term historical MRP and estimates of the MRP derived from dividend growth models.
2017	**Icon Water** **Weighted average cost of capital** Developed an expert report of the equity beta of US and UK water companies to assist in the development of a benchmark equity beta in the circumstances of Icon Water to be used in the 2018-2023 Regulatory Review of its regulated water and sewage services.
2017	**ActewAGL Retail, ACT** **Retail margin for regulated retail tariffs** Brendan co-authored a report responding to the Independent Competition and Regulatory Commission's (ICRC's) draft decision to change its methodology for determining the retail margin component of regulated electricity standing offer prices. We considered the adequacy of the ICRC's approach in light of the factors that may be expected to affect the costs recovered by the retail margin.
2014-16	**Sale of the Port of Melbourne** **Cost of capital and financial modelling** Provided strategic advice on economic regulation of the Port of Melbourne in the context of the proposed long term lease of the port by way of long term lease to Victorian Department of Treasury and Finance. Key tasks included to building of regulatory financial models for the lease period, and provided an indicative cost of capital estimate for the port.
2015	**Colonial First State Global Asset Management** **Due Diligence Report for the Vector Gas Transaction** Brendan was part of a team that provided strategic advice on economic regulation of the Vector gas transmission and distribution businesses in the context of sale. Our advice detailed the legal and institutional arrangements applying to New Zealand gas businesses and steps through the key factors considered by the Commerce Commission in its periodic determination of the applicable price-quality paths.
2015	**DLA Piper/Confidential Client** **Expert reports on the economic and regulatory principles of infrastructure pricing** Brendan provided strategic advice on the appropriate cost of capital and financial models for an Australian aeronautical services business.

2015	**ESCOSA** **Cost of capital for a benchmark water business** Provided a range of reports on the cost of capital for a benchmark water utility. Reports covered the use of different cost of equity models, the value of the MRP, gamma, and a trailing average cost of debt.
2015	**Sydney Water** **Equity beta for a regulated Australian water business** Brendan authored an expert report for submission to the IPART on empirical evidence of the equity beta for a benchmark Australian water network service provider.
2014-15	**Transgrid** **Cost of Capital** Co-authored two expert reports submitted by Transgrid in support of its 2014-18 revenue proposal. The expert report covered all aspects of the new cost of capital framework, including return on equity estimates generated by the CAPM, Black CAPM, the Fama-French three-factor model, and DGMs, and the approach method of transitioning to a trailing average cost of debt.
2014	**New Zealand Airports Association / Powerco (New Zealand)** **Review of the WACC Percentile** Brendan assisted in the preparation of two expert reports – one for the New Zealand Airports Association, and the other for Powerco – for submission to the New Zealand Commerce Commission in response to its review of the cost of capital input methodologies. The reports reviewed the Commission's approach to setting the regulatory WACC at the 75th percentile, discussed the economic rationale for setting a WACC above an unbiased midpoint estimate of the cost of capital, and considered the merits and practicability of undertaking an in-depth empirical estimate of the 'optimal' cost of capital percentile.
2014	**Queensland Competition Authority** **Price review** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for Queensland water utilities. The review considered the formulation of the WACC, the intra year timing of cash flows, and the structural, computational and economic integrity of the models.
2014	**DLA Piper/Confidential Client** **Expert reports on the economic and regulatory principles of infrastructure pricing** Brendan assisted in the preparation of three expert reports in relation to the economic and regulatory principles used to allocate shared costs, supporting peak pricing and developing an economic framework for pricing aeronautical services. In addition, Brendan provided strategic advice on the appropriate cost of capital and financial modelling.
2013-15	**Sydney Water Corporation** **Cost of capital estimation** Prepare three expert reports for submission to the IPART on the framework for determining the weighted average cost of capital for infrastructure service providers, and on estimation of an appropriate equity beta.

2013	**Essential Services Commission (ESC)** **Financeability discussion paper** Brendan drafted a discussion paper on the financeability testing of Victorian water utilities. The paper described the role and objective of financeability testing in the regulatory regime, assessed the various qualitative and quantitative indicators of financeability and recommended an approach to financeability testing for the ESC.
2013	**Queensland Competition Authority** **Price review** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for Queensland water utilities. The review considered the formulation of the WACC, the intra year timing of cash flows, and the structural, computational and economic integrity of the models.
2012-13	**Gilbert + Tobin/Rio Tinto Coal Australia** **Assistance in drafting expert report on port prices** Prepared analysis and expert reports in the context of an arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal. Issues addressed included asset valuation, cost of capital, forecast operation and maintenance costs and the economic interpretation of building block regulation.
2012-13	**Ashurst/Brisbane Airport Corporation** **Draft access undertaking** Provided advice, analysis and an expert report on the WACC in the context of the preparation of a draft access undertaking specifying the basis for determining a ten year price path for landing charges necessary to finance a new parallel runway at Brisbane airport.
2012	**APA GasNet** **Assistance in drafting cost of capital submission** Provided drafting assistance and strategic advice to APA on GasNet's cost of capital submission to the AER for the Victorian principal gas transmission network.
2012	**APA Brisbane to Roma Pipeline** **Assistance in drafting cost of capital submission** Provided drafting assistance and strategic advice to APA on the Brisbane to Roma Pipeline cost of capital submission to the AER.
2012	**Energy Networks Association** **Rate of return framework guideline** Co-authored a number of expert reports submitted to the AER on the rate of return framework guideline. These reports considered a range of financial issues including the applicability of various financial models to the estimation of the cost of equity; the estimates of the cost of equity from the Black CAPM; estimates of the historic market, size and value premiums; and the payout ratio of created imputation credits.
2012	**Energy Networks Association** **Advice on the new rate of return framework** Advice to the Energy Networks Association on the implications of the new allowed rate of return framework applying to electricity and gas transmission and distribution businesses. This report considered a range of financial models and other information that the regulator should have regard to when setting the regulated return on equity.

2012	**Victorian Gas Networks** **Black Capital Asset Pricing Model** Brendan co-authored a report that examined whether a version of the Black CAPM is better able than an empirical version of the Sharpe-Lintner (SL) CAPM to produce an estimate of the cost of equity that meets the requirements of Rule 87 (1) of the National Gas Rules (NGR). Following an examination of Australian financial data we concluded that an empirical version of the Black CAPM is better able than an empirical version the SL CAPM.
2011-12	**Energy Networks Association** **Review of Economic Regulation of Network Service Providers** Advice and expert reports submitted to the Australian Energy Market Commission on the new allowed rate of return framework to apply to electricity and gas transmission and distribution businesses, as proposed by the AER and the Energy Users Rule Change Committee.
2011-12	**Energy Networks Association** **Review of Economic Regulation of Network Service Providers** Advice and expert reports submitted to the Australian Energy Market Commission on the expenditure and incentive frameworks to apply to electricity transmission and distribution businesses, as proposed by the AER.
2011	**Multinet Gas and SP AusNet - Gas Distribution** **Report on the market risk premium** Co-authored a report that examined a number of issues arising from the draft decision on Envestra's access proposal for the SA gas network. The report considered whether the historical evidence supported the use of a long term average of 6 per cent; there is any evidence to warrant a MRP at it long term average; and the evidence relied on by the AER to justify its return to a MRP of 6 per cent.
2011	**Dampier to Bunbury Natural Gas Pipeline - Gas Transmission** **Cost of equity of a regulated natural gas pipeline** Co-authored two reports that updated the cost of equity for a gas transmission business and responded to issues raised by the regulator in its draft decision. The report re-estimated the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM, Fama-French three-factor model and a zero beta version of the Fama-French three-factor model.
2010-11	**Queensland Competition Authority** **Weighted Average Cost of Capital (WACC) for SunWater** Retained to provide two expert reports on the WACC for SunWater a Queensland rural infrastructure business. The first report considered issues pertaining to whether a single or multiple rates of return can be applied across SunWater's network segments. The second report focuses market evidence on the appropriate rate of return for SunWater.
2011	**Mallesons Stephens Jaques/ActewAGL Distribution** **Determining the averaging period** Assisted in the development of an expert report that considered the economic and financial matters arising from the AER's decision to reject ActewAGL's proposed risk free rate averaging period.
2010	**Industry Funds Management/Queensland Investment Corporation** **Due diligence, Port of Brisbane** Brendan was retained to advise on various regulatory and competition matters likely to affect the future financial and business performance of the Port of Brisbane, in the context of its sale by the Queensland government.

2010	**Dampier to Bunbury Natural Gas Pipeline – Gas Transmission** **Cost of equity of a regulated natural gas pipeline** Co-authored a report that examined four well accepted financial models to estimate the cost of equity for a gas transmission business. The report of estimating the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM, Fama-French three-factor model and a zero beta version of the Fama-French three-factor model.
2009-10	**Jemena – Gas Distribution** **Cost of equity of a regulated natural gas distribution network** Co-authored two reports on the use of the Fama-French three-factor model to estimate the cost of equity for regulated gas distribution business. The report examined whether the Fama-French three-factor model met the dual requirements of the National Gas Code to provide an accurate estimate of the cost of equity and be a well accepted financial model. Using Australian financial data the report also provided a current estimate of the cost of equity for Jemena.
2009	**WA Gas Networks** **Cost of equity of a regulated natural gas distribution network** Co-authored a report that examined a range of financial models that could be used to estimate the cost of equity for a gas distribution business. The report of estimating the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM, Fama-French three-factor model and Fama-French two-factor model. The report examined both the domestic and international data.
2009	**Jemena and ActewAGL** **Cost of equity of a regulated natural gas distribution network** Co-authored a report on alternative financial models for estimating the cost of equity. The report examined the implication of estimating the cost of equity of a gas distribution business using the Sharpe Lintner CAPM, Black CAPM and Fama-French models. The report examined both the domestic and international data.
2009	**Prime Infrastructure** **Sale of Dalrymple Bay Coal Terminal (DBCT)** Brendan provided regulatory advice to a number of potential bidders for the assets of DBCT. Advice included an assessment of the rate of return parameters, depreciation, regulatory modelling and the regulatory arrangements in Queensland.
2008	**Joint Industry Associations - APIA, ENA and Grid Australia** **Weighted Average Cost of Capital for a regulated energy network** Assisted in the drafting of the Joint Industry Associations submission to the AER's weighted average cost of capital review. The submission examined the current market evidence of the cost of capital for Australian regulated electricity transmission and distribution businesses.
2008	**Joint Industry Associations - APIA, ENA and Grid Australia** **Weighted Average Cost of Capital for a regulated energy network** Expert report for the Joint Industry Associations on the value of imputation credits. The expert report was attached to their submission to the AER's weighted average cost of capital review. The report examined the current evidence of the market value of imputation credits (gamma) created by Australian regulated electricity transmission and distribution businesses.

Industry Analysis

2025

Confidential client
Regulatory due diligence on a regulated water business in Australia
Provided sell-side due diligence report on the regulatory risks relating to a water business in Australia. The report described the regulatory framework that applied to the business, as well as the opportunities for investing in capital expenditure and for outperforming benchmark cost allowances and the regulatory rate of return.

2025

Confidential client
Regulatory due diligence on an electricity transmission network
Provided sell-side due diligence on the regulatory risks relating to an Australian electricity transmission network. The advice described the framework for governance and cost recovery, and discussed likely future regulatory developments and associated regulatory risks and opportunities.

2024

Confidential client
Regulatory due diligence and demand forecasting
Due diligence provided to a bidder for a stake in a New Zealand distribution electricity and gas network. Provided briefing note on the key regulatory issues affecting future cashflows as well as 50 year forecasts of electricity throughput and peak and future gas throughput and customer numbers.

2023-24

Confidential client
Regulatory due diligence report
Development of a regulatory due diligence report for the refinancing of a regulated energy infrastructure business. The report described the economic regulatory framework applying, including the cost of capital to the network and assessed the potential implications of the transition to a zero carbon energy market in Australia.

2022

Confidential client
Regulatory due diligence report relating to potential transaction
Development of a regulatory due diligence report for the sale of a regulated network service provider. The report described economic regulation as it applies to the relevant network business, the current and potential issues affecting the cost of capital and assessed the potential impact of the transition to a zero carbon energy market in the National Electricity Market.

2022

Confidential client
Regulatory due diligence report of a gas transmission pipeline
Development of a regulatory due diligence report for the unsuccessful purchase of a regulated gas transmission pipeline. The report described the economic regulatory framework applying, including the cost of capital to the network and assessed the potential implications of the transition to a zero carbon energy market in Australia.

2022

Confidential client
Input price forecasting
Provided price and cost forecasts to assist in support of bidder to be the Network Operator for the Central-West Orana renewable energy zone. Including analysis of historical variation and correlation of price series to assess the risk of the bid.

2022	**Confidential client** **Regulatory due diligence report** Development of a regulatory due diligence report for a party interested in becoming the Network Operator under the New South Wales Electricity Infrastructure Roadmap contestable process for the Central-West Orana renewable energy zone. The report described the bespoke economic regulatory framework developed applying to network businesses under the New South Wales arrangements.
2022	**Confidential client** **Preparation of a market due diligence report** Due diligence market report that assessed the Australian and New Zealand regulatory framework for metering, and potential size of the metering markets in support of the potential purchase of a 50 per cent stake in Vector Metering's Australian and New Zealand business.
2022	**Confidential client** **Due diligence to support purchase of Eastland Network in NZ** Expert advice to support the development of a regulatory due diligence report in the context of the purchase of Eastland Network.
2022	**Queensland Department of Energy and Public Works** **Electricity incentives package development** Developed a package of incentives that the Queensland Government could use to incentivise large electricity loads to connect in renewable energy zones and priority areas. This involved consultation with stakeholders, research and development of transmission related incentives, development of a decision framework for applying potential incentives, and developing an input-output multiplier tool to quantify the impacts of incentives.
2021	**Essential Energy** **Strategic advice and support relating to the NSW Energy Roadmap** Brendan supported Essential Energy engaging with the development of regulations that will underpin the development of renewable energy zones under the NSW Energy Roadmap.
2021	**DLA Piper** **Aeronautical pricing** Brendan worked with DLA Piper to advise a major Australian airport on the pricing of aeronautical services. Advice included the operation of building block models, the appropriate cost of capital, depreciation and cost of tax.
2021	**DLA Piper/Sydney Airport** **Aeronautical pricing and impact of the pandemic** Brendan was a member of team that provided advice to DLA/Sydney Airport on behalf of the impact of COVID-19 on the aeronautical charges at Sydney Airport. Our advice included the impact of the pandemic on prevailing estimates of the cost of capital, potential methods to mitigate the future risk of asymmetric events, assessment of options that are consistent with the aeronautical pricing principles ensure that the airport is compensated for unforeseen past events.

2021	**AustralianSuper** **Regulatory due diligence report relating to the sale of a stake in Ausgrid** Regulatory due diligence report for the sale by AustralianSuper of its stake in Ausgrid. The advice covered the current regulatory and market environment in the National Electricity Market, and the implications to transmission and distribution networks of changing technology and the process of decarbonisation in the NEM as well as developments in the cost of capital for regulated energy networks.
2021	**Brookfield Asset Management** **Regulatory due diligence report relating to the purchase of AusNet** Regulatory due diligence report for the purchase of AusNet's electricity transmission and distribution and gas networks. The advice covered the current regulatory and market environment in the National Electricity Market and National Gas Market, and the implications to electricity transmission, electricity distribution and gas distribution networks of changing technology and the process of decarbonisation in the NEM/NGM as well as developments in the cost of capital for regulated energy networks.
2021	**REST Infrastructure Pty Limited** **Regulatory due diligence report relating to the sale of 50 per cent of the SEA gas pipeline system** Regulatory due diligence of the legal and institutional arrangements applying to the natural gas market in Australia, particularly as they relate to the economic regulation of gas transmission pipelines, including SEA Gas. The report focused on the current regulatory framework and the proposed policy options recently released by Energy Ministers for the natural gas market.
2021	**Australia, Confidential client** **Regulatory due diligence report relating to the purchase of SKI** Regulatory due diligence report to the purchase of SKI by KKR, OTPP and PSP. The advice covered the current regulatory and market environment in the National Electricity Market, and the implications to transmission and distribution networks of changing technology and the process of decarbonisation in the NEM as well as developments in the cost of capital for regulated energy networks.
2021	**Department of Infrastructure, Transport, Regional Development and Communications** **Sustainable regional airport security screening network pricing mechanism** Brendan led a team that modelled and provided analysis to independently advise on support mechanisms for the recovery of the costs associated with security screening at specified regional airports. This project considered whether increased screening requirements would result in uncommercial cost recovery, threaten the viability of regional airports and/or unfairly disadvantage regional communities.

2019	**Brookfield Infrastructure Group** **Seller regulatory due diligence** Assisted in the development of a regulatory due diligence report of a company the sale of the Dalrymple Bay Coal Terminal (DBCT) by Brookfield Infrastructure Group. Our advice set out the current regulatory arrangements that apply to the coal handling service at the DBCT in relation to revenue, prices and capacity expansions. Brendan led the works stream assessing Queensland Competition Authority's approach to setting annual revenues including the cost of capital.
2019	**Confidential client** **Due Diligence Report on the sale of Enwave assets** Brendan was part of a team that provided strategic advice on economic regulation of the Enwave's Tasmanian and Victorian gas distribution businesses, and district energy and utility network. Our advice detailed the legal and institutional arrangements applying to gas businesses and the potential operation of Part 23 of the National Gas Rules and the new framework apply to embedded networks.

Regulatory Analysis

2025	**Western Power** **Options to expedited connection to the electricity network** Led a team that assisted Western Power to develop options to modify their connection policy for residential housing developments suitable for expedited connection to the electricity network in the short and longer term. To assess different options we developed an economic assessment framework that had regard to economic efficiency, equity, government policy and administrative complexity.
2025	**Western Power** **Review of the gainshare mechanism for AA6** Reviewed the design of the Gain Sharing Mechanism (GSM) and assessed whether the mechanism applied in AA5 would lead to windfall gains/losses that are inconsistent with the Electricity Network Access Code 2004 (ENAC) and GSM objectives. The advice outlined the amendments necessary for the GSM to provide an equitable allocation between users and Western Power of any innovation and efficiency gains or losses.
2025	**Western Power** **Reliability Regulation Reform Recommendations** Advised Western Power on the development of recommendations for reform on the reliability framework applying to electricity transmission and distribution service providers in Western Australia. This project was delivered two stages. The first stage comprised a review of frameworks applying to transmission and distribution service providers in a range of comparator jurisdictions and the development of options for reform of the reliability framework in Western Australia, drawing on our findings from our scan of other jurisdictions. The second stage comprised the further analysis and development of the stage one shortlisted recommended options for reform.

2024-25	**Jemena Electricity Networks (JEN)** **Repex modelling to support 2026-31 regulatory proposal** Applied and drafted a supporting report on the AER's replacement expenditure (repex) model for JEN. This included developing a novel methodology to calculate average age at replacement using JEN's regulatory information notice (RIN) data.
2024	**Barrenjoey/Confidential client** **Analysis of transmission network regulatory environment** Led a team that prepared expert reports detailing the current and future risks and opportunities in relation to the rate of return and incentive schemes (CESS, EBSS and STPIS), which formed part of a due diligence report for proposed investment in a transmission network service provider.
2024	**Botten Dnistriansky Kellis Lawyers** **STPIS damages** Quantified the damages from the operation of the AER's Service Target Performance Incentive Scheme (STPIS) on SA Power Network's revenues associated heavy vehicle incident that resulted in a loss of supply.
2024	**Hall and Wilcox Lawyers / RACV Insurance** **STPIS damages assessment** Authored three expert reports that assessed the damages associated with service target performance incentive scheme (STPIS) penalties to NEM distribution networks arising from collisions by motor vehicles to the networks' infrastructure
2024	**Transgrid** **Application of incentive mechanisms to HumeLink** Provided an expert report submitted to the regulator on whether the capital expenditure sharing scheme (CESS) should be modified for HumeLink project. The report assessed whether applying the current CESS unaltered to HumeLink project would be consistent with the National Electricity Objective.
2024	**Confidential client** **Powerco (NZ) due diligence** Led a team providing two due diligence reports to a potential buyer of a stake in Powerco, a New Zealand electricity and gas distribution business. Our support including analysis on future gas and electricity demand, and prioritised regulatory issues.
2023-24	**Marinus Link, Advice on Contingent Risk Cost** Brendan provided advice on contingent risk costs estimated by Marinus Link and whether it would likely be accepted by the AER. Brendan also helped draft Marinus Link's submission to the AER.
2023- on-going	**CopperString, Queensland** **Regulatory advisor to project team** Brendan was part of a team that provided specialist regulatory input to the CopperString project team in relation to the regulatory arrangements that should apply to the project under Queensland legislation to enable its eventual integration with the NER regulatory arrangements, whilst ensuring Queensland customers benefit from the project.

2023	**Independent Pricing and Regulatory Tribunal** **Sydney Desalination Plant pricing review** Advised IPART in its 2023 pricing review of Sydney Desalinations Plant (SDP). This included an evaluation of whether proposed incentive mechanisms, cost pass-throughs, re-openers and true-ups incentivised SDP to operate in the long term interests of consumers.
2022-23	**Confidential clients** **Two separate reviews of vendor financial models relating to potential transactions** Reviewed the vendor financial models of two separate energy networks. The review covered the economic and financial logic of the model, the applicable incentive schemes, the correct calculation of indexation and depreciation.
2022	**Independent Pricing and Regulatory Tribunal** **Water pricing framework review** Expert advice on the incentive mechanisms to be applied in the new water pricing regulatory framework. Brendan also assisted the Tribunal in developing the expenditure incentive mechanisms included in its final decision for Sydney Desalination plant.
2022	**Manildra** **The economic regulation of a price cap on wholesale ethanol** Brendan provided Manildra with analysis and a letter to IPART on the appropriateness of retaining the annual resetting mechanism for wholesale ethanol prices. This support included analysis of trend in IPART's benchmark wholesale import parity price and the implication of returning to a quarterly resetting of the price cap.
2022	**Hall and Wilcox** **Assessment of penalties under the service quality incentive scheme** Brendan estimated the financial penalty imposed by STPIS an electricity distribution network would experience from a motor vehicle accident that disrupted network electricity services.
2021	**Independent Pricing and Regulatory Tribunal (IPART)** **Opex, capex and service quality incentive schemes for regulated water businesses** Brendan advised the IPART on the implementation of incentive schemes for regulated water utilities in NSW. This included the development of technical documents and an indicative model for calculating incentive payments.
2021	**Energy Networks Australia (ENA)** **Advice on the incentive schemes applying to electricity and gas networks** Brendan provided strategic advice to the ENA on its response to the AER's 2022 review of the incentive schemes operating on electricity and gas networks. Brendan also provided a public report that estimates the customer benefits attributable to the AER's incentive mechanisms over the 2006 to 2020 period.
2021	**Dalrymple Bay Infrastructure** **Estimate of benchmark corporate costs** Brendan estimated for DBI the benchmark corporate costs of an export coal terminal in the context of its new light handed access framework for the DBCT service under the Queensland Competition Act.

2021	**Manildra** **The economic regulation of a price cap on wholesale ethanol** Brendan provided support to Manildra responding to IPART's 2022 review of the approach to determining wholesale ethanol. This support included strategic advice of the implication of the key issues raised by IPART and stakeholders and developing Manildra's response to IPART the NSW economic regulator.
2021	**Clayton Utz/Port of Newcastle** **Navigation services business case** Development of business case to support recovery of navigation expenditure in relation to Port of Newcastle's proposed multi-purpose deepwater terminal.
2020-21	**DLA Piper/ Australian Airport** **Economic support in the determination of aeronautical charges** Provided economic advice to DLA and an Australian airport in the context of ongoing litigation on the price of aeronautical services provided by an Australian airport.
2020-21	**Clayton Utz/Port of Newcastle** **Determination of the navigation service charge** Provided advice to Clayton Utz and the Port of Newcastle on the calculation of navigation service charge in the context of the arbitration with Whitehaven Coal. Advice included the calculation of the rate of return, regulatory model and the determination of an initial asset value of navigation assets.
2020	**Jemena Energy Networks** **Efficiency implication of removing the EBSS** Brendan authored an expert report on incentive implications of either applying, or not applying, the EBSS to Jemena's operating expenditure performance for the period commencing on 1 July 2021 through to 30 June 2026. This report was submitted to the AER in the context of its draft decision for Jemena's Victorian electricity distribution network.
2020	**Australian Energy Markets Authority/Energy Security Board** **Assistance with cost allocation modelling** Brendan provided developed a cash flow model for projects included in the national Integrated System Plan (ISP). This advice included assessment of a reasonable rate of return and depreciation assumptions for each project.
2020	**IPART, NSW** **Distributor incentives to efficiently incur DER export capacity** Brendan was part of team that provided advice on an appropriate regulatory framework and associated measures to incorporate the value that customers place on reliably exporting power to distribution networks using DER. In addition to providing an export report this project also required consultation with distributors, AER, AEMC, AEMO, and aggregators/retailers.
2020	**IPART, NSW** **Interaction between regulatory financial incentives and the NSW licence conditions on reliability outcomes for distributors** Brendan provided an expert report that assessed the incentives that apply to the NSW distributors under the national regulatory framework in relation to the reliability provided by their networks, and how this is affected by standards mandated in their NSW distribution licences.

2019	**DLA Piper, confidential client** **Assistance with the setting of aeronautical prices** Brendan provided expert economic and regulatory advice to DLA Piper on the setting of aeronautical prices at an Australian state capital airport. The advice include the assessment of asset valuation principles, WACC, pricing models and measuring the willingness-to-pay of airlines.
2019	**Transgrid** **Application of contingent project framework to projects spanning two regulatory periods.** Brendan advised Transgrid on the application of the contingent project framework in the context of a project that spans more than one regulatory period, and appropriate options for addressing investment cost uncertainty.
2016-19	**HWL Ebsworth/ Confidential Client, Australia** **Price for public lighting services** Assisted with the preparation of an expert report and support during a hearing before the AER, which examined the appropriate price for public lighting, based on the use of a standard regulatory approach.
2018	**Ausgrid** **Assistance with the remittal determination** Brendan provided strategic advice to Ausgrid on its submissions to the AER on its 2018 remittal decision. This advice focused on the calculation of the required opex and revenue allowance for the 2014-18 period, the capital expenditure sharing scheme carry forward amounts for the 2018-23 period.
2018	**Public Utilities Office, Western Australia** **Review of the WA Access Code in light of new technologies** Brendan advised the PUO as part of its proposed review of potential changes to the regulatory framework for electricity networks set out in the Access Code arising from innovation/technology in the electricity market.
2018	**Confidential client** **Options for the allocation of demand and technology risks** We explored whether there are realistic potential options to alter the risk allocation between customers and network businesses on a forward-looking basis, in a manner that supports positive long-term customer outcomes. Specifically, our report considered the allocation of demand and technology risks for new investment, and the resulting implications for the efficiency of future capital investment.
2018	**Essential Energy** **Telephone answering STPIS performance** Provided advice on Essential Energy’s calculations and reporting practices for service targets performance incentive scheme (STPIS), ensuring they were compliant with rules set out for the for telephone answering. Our advice also extended to improving reporting processes and developing STPIS performance calculation templates that assist with performance monitoring.

2018	**Essential Energy** **Evaluation of the growth in the RAB since economic regulation** Brendan managed a team analysing to the drivers of growth in Essential Energy's regulatory asset base since the start of economic regulation in 1998 to 2019. This analysis identified and quantified a range of factors that have contributed to growth and identified options to manage future growth in the RAB.
2018	**Ausgrid** **Estimation of standalone and avoidable costs** Brendan authored an expert report that estimated the standalone and avoidable cost of Ausgrid's distribution network for the 2019-24 regulatory period. This report was attached to Ausgrid 2018 regulatory proposal to the AER.
2017	**ActewAGL Distribution** **Remittal opex strategy** Brendan, together with Ann Whitfield, has been advising ActewAGL Distribution on potential strategies for the remittal of its operating expenditure allowance for the 2014-19 period. This assistance includes decision modelling the financial implications of different strategies, potential implications for the 2019 revenue reset, the interaction with the AER's opex incentive mechanism (EBSS), and the implications of adverse capital expenditure and service quality outcomes.
2017	**Transgrid** **Review of the capital expenditure incentive scheme** Brendan prepared an expert report that assessed whether the AER's capital expenditure sharing scheme (CESS) correctly provided the network with a 30 per cent share of total efficiency gains and losses. The review found a number of errors in the incentive mechanism. All the principal changes suggested in the expert report were accepted by the AER in its final decision for Transgrid.
2017	**Endeavour Energy** **Development of its opex proposal** Brendan provided strategic advice to Endeavour Energy on its operating expenditure allowance proposal for its 2019-24 regulatory reset.
2016-2017	**Icon Water, ACT** **Workshop on key regulatory issues** Brendan facilitated a series of workshops for Icon Water's senior management on key aspects of their upcoming regulatory submission for their water and wastewater business, including the rate of return, regulatory modelling and depreciation.
2016	**DLA Piper** **Appeal by the Victorian DNSPs** Brendan provided submission to the Australian Competition Tribunal on the application of the efficiency benefit sharing scheme (EBSS) on behalf of the Victorian DNSP's.
2016	**Manildra** **The economic regulation of a price cap on wholesale ethanol** Brendan provided strategic advice to Manildra on the potential introduction of a maximum wholesale price, or pricing mechanism, for ethanol in NSW. This advice included the development of an expert report that was submitted to the IPART the NSW economic regulator.

2016	**Western Power** **Regulatory assistance** Regulatory advisor to Western Power on its proposed move to the national electricity market. The advice included assistance in developing regulatory incentive mechanisms, cost of capital, depreciation, opex, asset roll forward, regulatory revenue, and tariff design.
2015-16	**Government of New South Wales** **Economic regulation for privatisation** Advisor to government of New South Wales on all economic regulatory aspects of the proposed partial lease the electricity transmission and distribution entities, Transgrid, AusGrid and Endeavour Energy.
2015	**ActewAGL GAS Distribution** **Operation of the efficiency benefit sharing scheme** Brendan provided an independent expert report responding to the AER's draft decision on the efficiency benefit sharing scheme (EBSS) carry forward amounts to be included in the revenues for 2016/17 to 2020/21 period.
2015	**Jemena Gas Networks** **Estimation of standalone, avoidable and LRMC of the ACT gas network** Brendan authored an expert report that estimated the standalone, avoidable and long-run marginal cost of the ACT gas network. This report was submitted to the AER as part of ActewAGL's 2015 access arrangement proposal.
2015	**SA Power Networks** **Expert report on regulatory depreciation** Brendan authored an expert report for submission to the AER on whether SA Power Network's the proposed depreciation schedules were compliant with the requirements of the National Electricity Rules to depreciate assets over their economic lives.
2015	**Ergon Energy** **Review of regulatory depreciation** Provided Ergon with an internal strategy paper assessing different methods for calculating the remaining lives of asset or groups of assets.
2014/15	**ActewAGL Electricity Distribution** **Incentive arrangements applying with opex benchmarking** Brendan authored an expert report on the application of the EBSS for ActewAGL electricity distribution in the circumstances where the regulator has not used revealed costs to determine the forthcoming opex allowance. This report focuses on the incentive arrangements existing for ActewAGL and whether these arrangements are consistent with the national electricity objective.
2014	**Ausgrid** **Application of the AER's efficiency benefit sharing scheme** Brendan provided expert advice to Ausgrid on the estimation of the efficiency carry-forward to be applied in the 2014-19 period. This advice extended to strategic advice on the implications of the AER's Better Regulation new EBSS.

2014	**ActewAGL Gas Distribution** **Tariff control mechanism for gas distribution network** Brendan provided analysis and advice in relation to the tariff variation mechanisms available under the National Gas Rules (NGR), and the issues that ActewAGL should consider in arriving at a decision on the mechanism to be proposed in its 2016-21 gas network access arrangement.
2014	**Johnson Winter & Slattery/ATCO GAS** **Application of depreciation options under the new gas rules** Assisted in the drafting of an expert report on depreciation options consistent with the new gas rules for ATCO Gas for submission to the Economic Regulation Authority of Western Australia.
2013	**Energy Networks Association** **Submission to the AER's Proposed Efficiency Incentive Schemes** Brendan led a team that undertook to quantitatively investigate the incentive properties of the AER's proposed efficiency schemes. The output of this assignment was an expert report to the AER's Better Regulation issues paper and internal advice to the ENS on the implications on aspects of the draft determination.
2013	**Actew Corporation** **Interpretation of economic terms** Advice on economic aspects of the draft and final decisions of the Independent Competition and Regulatory Commission in relation to the price controls applying to Actew.
2012-13	**Gilbert + Tobin/Rio Tinto Coal Australia** **Assistance in drafting expert report on port prices** Analysis and expert reports prepared in the context of an arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal. Issues addressed included asset valuation, cost of capital, forecast operation and maintenance costs and the economic interpretation of building block regulation.
2012	**ACTEW Water** **Review of regulatory models** Brendan provided strategic and analytical advice to ACTEW on its regulatory models. The analysis included analysis of the risks and challenges of adopting a post-tax revenue model and the application of expenditure incentive mechanisms.
2012	**Queensland Competition Authority** **Review of the retail water regulatory models** Brendan undertook an independent quality assurance assessment of the financial models relied on by the QCA to set the regulated revenues of SunWater. The review considered: SunWater's Financial model, a model used by SunWater to calculate future electricity prices, an renewals annuity model, as well as the QCA's regulatory model. These models established a set of recommended prices for each of the 30 irrigation schemes operated by SunWater for the period 2014 to 2019.
2011	**Queensland Competition Authority** **Review of the retail water regulatory models** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for Queensland Urban Utilities, Allconnex Water, and Unitywater. The review considered: the formulation of the WACC; the intra year timing of cashflows; and the structural, computational and economic integrity of the models.

2011	**Western Power** **Review of Service Standards and Incentive Framework for AA3** Brendan co-authored an expert report for Western Power that advised whether the proposed service standard framework was consistent with the Access Code and provided appropriate incentives for efficiency in the long term interests of consumers.
2011	**Queensland Competition Authority** **Review of the wholesale water regulatory models** Undertook an independent quality assurance assessment of the models used to calculate regulated revenues for LinkWater, Seqwater; and WaterSecure. The review considered: the formulation of the WACC; the intra year timing of cashflows; and the structural, computational and economic integrity of the models.
2010-11	**Minter Ellison /UNELCO** **Review of regulatory decision by the Vanuatu regulator** Assisted in the development of an expert report on a range of matters arising from the Vanuatu regulator's decision to reset electricity prices under four concession contracts held by UNELCO. The matters considered included the methodology employed to calculate the new base price, the appropriateness of the rate of return, the decision by the regulator to reset future prices having regard to past gains/losses.
2010	**Orion Energy, New Zealand** **Information disclosure regime** Provided advice and assistance in preparing submissions by Orion to the New Zealand Commerce Commission, in relation to the Commission's proposed weighted average cost of capital for an electricity lines businesses. Issues addressed included the financial model used to calculate the required return on equity, the appropriate term for the risk free rate and the WACC parameter values proposed by the Commission.
2010	**Grid Australia** **Amendments to the AER's transmission revenue and asset value models** Developed and drafted a submission to the AER on the proposed amendments to the AER's post-tax revenue model (PTRM) and roll forward model (RFM). The proposal focused on a number of suggestions to simplify and increase the usability of the existing models.
2009	**CitiPower and Powercor – Victorian Electricity Distribution** **Network Reliability Incentive Mechanism (S-factor)** Brendan was engaged by CitiPower and Powercor to provide advice on the proposed changes to the operation of the reliability incentive mechanism and was subsequently engaged to analysis the final version of the new arrangements. The advice considered the effects of the proposed changes to the operation of the two distribution network service providers. Specifically, how the 'S-factors' would be changed and implications this has to the revenue streams of the two businesses. A comparison was also made with the current ESC arrangements to highlight the changes to the mechanism.

2007	**Electricity Transmission Network Owners Forum (ETNOF)** **Amendments to the AER's transmission revenue and asset value models** Developed and drafted a submission to the AER on the proposed post-tax revenue model (PTRM) and roll forward model (RFM) that would apply to all electricity transmission network service providers (TNSPs). The proposal focused ensuring that the regulatory models gave effect to the AER's regulatory decisions and insures that TNSPs have a reasonable opportunity to recover their efficient costs.
2001-02	**Independent Pricing and Regulatory Tribunal (IPART), NSW** **Review of Energy Licensing Regime** Brendan was a member of a team that reviewed the electricity and gas licensing regime in NSW. Brendan assessed the need for minimum performance standards for licensed electricity and gas businesses.

Policy

2021	**Essential Energy** **Strategic advice on the development and implementation of the NSW Roadmap** Brendan provided strategic advice to Essential Energy on the development of the regulations underpinning the implementation of the NSW Roadmap. This included the development of the: economic assessment framework to apply to the designated renewable energy zones (REZs); the costs recovery mechanism, the Consumer Trustee, and the implementation to the Central West REZ.
2021	**Clean Energy Finance Corporation (CEFC)** **Concessional Financing** Brendan was a member of a team that provided advice to the CEFC on how concessional financing arrangements for network and non-network investments could be used to benefit consumers. This included an analysis of the regulatory framework in the NEM to assess how concessional financing could influence the cost-benefit analysis for ISP, RIT-T, RIT-D projects, targeted consultation with the AEMC, AER, ENA, networks businesses and consumer groups. It culminated in a recommendation on whether a rule change would likely be successful and, if so, how they could do so most efficiently.
2019	**Confidential client** **Government agency resourcing review** Undertook a detailed review of the resourcing requirements of a high-profile government agency. The review involved establishing an understanding of all the major functions of the agency, the drivers of the agency's activity and the development of several resourcing scenarios.
2010	**Ministerial Council on Energy, Smart Meter Working Group** **The costs and benefits of electricity smart metering infrastructure in rural and remote communities** Part of a project team that extended earlier analysis of the costs and benefits of a mandatory roll out of smart meters, by considering the implications of a roll out in rural and remote communities in the Northern Territory, Western Australia and Queensland. The project focused on eight case study communities and examined the implications of prepayment metering and remoteness on the overall costs and benefits of a roll out.

2007-08	**Ministerial Council on Energy, Smart Meter Working Group** **Assessment of the costs and benefits of a national mandated rollout of smart metering and direct load control** Part of a project team that considered the costs and benefits of a national mandated rollout of electricity smart meters. Brendan was primarily responsible for the collection of data and the modelling of the overall costs and benefits of smart metering functions and scenarios. The analysis also considering the likely costs and benefits associated with the likely demand responses from consumers and impacts on vulnerable customers.
2005-06	**Minter Ellison and Freehills/Santos** **Gas supply agreement arbitration** Assisted in the development of an expert report on an arbitration of the price to apply following review of substantial gas supply agreement between the South West Queensland gas producers and a large industrial customer.

Sworn, transcribed evidence

2024	**Expert evidence before the Supreme Court of Victoria on behalf of plaintiffs, in the matters of Fox & Anor v Westpac & Anor (S ECI 2020 02946) and Nathan v Macquarie (S ECI 2020 03924)** Expert reports, sworn evidence, Melbourne, 30-31 October 2024

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