MANAGING UNCERTAINTY

CP ATT 10.01 – PUBLIC

2026–31 REGULATORY PROPOSAL

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1. Summary

We operate in an uncertain environment, which will only become more uncertain as Australia, and in particular, Victoria, continues moving through the energy transition. This appendix sets how we propose to handle this uncertainty through the 2026–31 regulatory period.

The AER has recognised, in recent regulatory decisions, that it is a challenging time for energy consumers, and the sector more broadly. It has noted in these decisions that it aims to balance affordability with allowing necessary expenditure required to support the energy transition.[1]

This proposal has been designed with this objective in mind. We have aimed to prioritise the interests of Victorian electricity consumers, while ensuring we are able to undertake the necessary expenditure to support the energy transition. We have carefully considered our forecast expenditure for the 2026–31 period, and decided to provide for certain events and projects using the National Electricity Rules (NER) mechanisms for managing uncertainty, rather than in our forecast capital and operating expenditure.

In our view, our proposal strikes an appropriate balance between reducing the burden for Victorian electricity consumers, while ensuring that we are able to recover our efficient and prudent costs of providing direct control services, when we incur those costs as a result of an unexpected event, or where the costs of an anticipated event may not be able to be forecast with certainty.

The 'uncertainty regime' under the NER comprises:

- pass through events
- capital expenditure reopeners
- contingent projects.

The AER is required, by clause 6.12.1 of the NER, to make constituent decisions in respect of the additional pass through events and the contingent projects proposed in a distribution network service provider's (distributor) regulatory proposal. This appendix contains our proposed additional pass through events and contingent projects, for the purposes of the AER's constituent decisions under clauses 6.12.1(14) and 6.12.1(4A) respectively.

1.1 Pass through events

The pass through mechanism in the NER recognises that a distributor can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass through enables a distributor to recover the costs of a defined unpredictable, high cost event that was not included in the AER's distribution determination.

Clause 6.6.1 of the NER provides for four already-defined pass through events for the purposes of a distribution determination, being:

- a regulatory change event
- a service standard event
- a tax change event, and

[1] AER, *Overview – Evoenergy Electricity Distribution Determination 2024 – 2029*, April 2024, p. vii; AER, Overview – Final Decision – Ausgrid Electricity Distribution Determination 2024 – 2029, April 2024, p. viii; AER, Overview – Final Decision – Endeavour Energy Electricity Distribution Determination 2024 – 2029, April 2024, p. viii.

- a retailer insolvency event.

In addition, clause 6.6.1(5) provides that a distribution determination may specify other events as pass through events. We propose seven additional pass through events for the purposes of clause 6.6.1(5), set out in the table below, with three being new pass through events.

TABLE 1 NOMINATED PASS THROUGH EVENTS

TYPE OF EVENT	CHANGES FROM CURRENT DEFINITION
Insurer credit risk event	No changes proposed from current definition
Insurance coverage event	No changes proposed from current definition
Natural disaster event	No changes proposed from current definition
Terrorism event	No changes proposed from current definition
Retailer insolvency event	No changes proposed from current definition
Fault level event	Additional event to address the risk that a part or parts of the distribution network will exceed fault level limitations and require upgrades to comply with relevant safety, contractual and regulatory obligations
Electrification event	Additional event to address the uncertainty around the pace of electrification, as electrification requires additional investment in the network
AEMO participant fee event	Additional event to address the potential for AEMO to alter its electricity market participant fees leading to a material increase in the costs to us in providing direct control services

We consider that each of the nominated pass through events set out above is consistent with the nominated pass through event considerations, as:[2]

- the events are not covered by a category of pass through event specified in clause 6.6.1(a1) to (4) of the NER
- the nature and type of each of the events has been clearly defined
- a prudent service provider could not reasonably prevent events of this nature or type from occurring or substantially mitigate the cost impact of such events
- we are unable to commercially insure or self-insure against the events.

Further, with the exception of the electrification event, AEMO participant fee event and fault level event, each of the proposed nominated pass through events is consistent with the nominated pass

[2] Clause 6.5.10(b) and the definition of 'nominated pass through event considerations' in Chapter 10 of the NER.

through events accepted by the AER in its previous distribution determinations for Victorian distributors, and the AER's recent distribution determinations for other distributors.[3]

1.2 Contingent projects

The contingent projects mechanism in the NER recognises that, unlike competitive businesses which are able to adjust their behaviour in response to uncontrollable factors, a distributor is generally obliged to continue to supply services, even where their equipment is exposed to significant risks.[4] A contingent project is a project that is reasonably required to be undertaken, but is excluded from a distributor's general capital expenditure allowance because of uncertainty about its requirement, timing or costs.

In comparison to a cost pass through, contingent projects are intended to apply to matters that are more specific to a particular business, and are more likely to occur than a pass through event.

To be accepted as a contingent project in a distribution determination, a project must have a clearly defined trigger event, which, if it occurs during the regulatory period, allows a distributor to recover incremental revenue during the period based on the capital and incremental operating expenditure reasonably required for the purpose of undertaking the project.

Additionally, the capital expenditure component of a project must be greater than either $30 million or five per cent of the annual revenue requirement of the distributor for the first year of the regulatory period, whichever is the greater amount.

We propose the following contingent projects for the 2026-31 regulatory period.

TABLE 2 PROPOSED CONTINGENT PROJECTS ($M, 2026)

PROPOSED PROJECT	CAPEX
LS Zone Substation Rebuild	70
J Zone Substation Rebuild	54
R Zone Substation Rebuild	68

[3] See, for example, Attachment 15 of Ausgrid's Distribution Determination 2024 – 2029 and Attachment 15 of Endeavour Energy's Distribution Determination 2024 – 2029. We note that these determinations do not include a separate nominated 'retailer insolvency event', as that event is specific to Victorian distributors given the inapplicability of the National Energy Retail Law in Victoria and the need for certain defined terms in the definition of 'retailer insolvency event' to be amended for consistency with the Victorian regime.

[4] AEMC, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, pp. 185-186.

2. Nominated pass through events

2.1 Background

The regulatory framework recognises that a distributor cannot reasonably be expected to forecast costs (capital and/or operating expenditure) for all foreseen and unforeseen events over a regulatory period. The NER addresses this issue by including a cost pass through mechanism, which allows distributors to seek the AER's approval to recover (or 'pass through') the costs or savings of defined, unpredictable, high cost events for which the distribution determination does not provide a regulatory allowance.[5]

The pass through mechanism allows distributors, with the AER's approval, to recover the efficient costs of events that could not be forecast as part of their regulatory proposals. Without this mechanism, the occurrence of such events would have a significant detrimental impact on distributors' ability to invest in and operate their networks.[6]

The Australian Energy Market Commission (AEMC) has recognised that specification of nominated pass through events is necessary to ensure that distributors are provided with the opportunity to recover their efficient costs, where those costs result from unforeseen and uncontrollable events for which insurance is limited or not available on commercial terms, and self-insurance is not appropriate.[7] In the absence of cost pass throughs in these circumstances, the AEMC recognised that efficient investment in, and efficient operation of, a distributor's network would likely be adversely affected over the long term, contrary to the National Electricity Objective (NEO).[8] That is, the specification of a nominated pass through event is necessary, and contributes to the achievement of the NEO, where that event is consistent with the nominated pass through event considerations specified in the NER.

2.2 NER requirements

Clause 6.6.1 of the NER specifies the following pass through events:

- a regulatory change event
- a service standard event
- a tax change event
- a retailer insolvency event
- any other event specified in a distribution determination as a pass through event for the determination.

The NER permits us to nominate additional pass through events in our regulatory proposal. When nominating these events, we must have regard to the 'nominated pass through event considerations'.[9] The AER must have regard to these same considerations when determining whether to accept the events we have nominated.[10] These considerations are:

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5 The pass through mechanism is contained in clause 6.6.1 of the NER.

6 Recognised by the AEMC in Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, pp. 2 and 9.

7 AEMC, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, pp. 18 to 19.

8 AEMC, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, p. 18.

9 Clause 6.5.10(a).

10 Clause 6.5.10(b).

- whether the event proposed is already covered by the pass through events specified in clause 6.6.1(a1) to (4) of the NER;
- whether the nature or type of event can be clearly identified at the time the distribution determination is made;
- whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;
- whether the relevant service provider could insure against the event, having regard to:
  - the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or
  - whether the event can be self-insured on the basis that:
    - it is possible to calculate the self-insurance premium; and
    - the potential cost to the distributor would not have a significant impact on the distributor's ability to provide network services; and
- any other matter the AER considers relevant and which the AER has notified network service providers is a nominated pass through event consideration.

As at the date of this proposal, the AER has not notified us of any other matter that is a nominated pass through event consideration.

In addition to having regard to the nominated pass through event considerations, the AER must:

- make its decision on whether to accept our nominated pass through events in a manner that will or is likely to contribute to the achievement of the NEO;[11] and
- take into account the revenue and pricing principles, as the decision relates to direct control network services.[12]

The NEO is set out in section 7 of the NEL, as follows:

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

The revenue and pricing principles are set out in section 7A of the NEL, with relevant extracts as follows:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(a) providing direct control network services; and*

11 As the AER is exercising an 'AER economic regulatory function or power' when making this decision (see the definition of that term in section 2(1) of the National Electricity Law (**NEL**)), it must comply with the requirement in section 16(1)(a) of the NEL in making this determination.

12 NEL, section 16(2)(a).

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

…

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

2.3 Our proposed nominated pass through events

As set out above in table 1, we propose the following nominated pass through events:

- insurer credit risk event
- insurance coverage event
- natural disaster event
- terrorism event
- retailer insolvency event
- fault level event
- electrification event
- AEMO participant fee event.

We set out further details on each of these events and how they satisfy the nominated pass through event considerations below.

2.3.1 Insurer credit risk event

We have included an insurer credit risk event in our 2026-31 regulatory proposal, consistent with our 2021-26 determination, designed to cover a situation where an insurer of ours becomes insolvent and, as a result, we are subject to higher or lower costs, a higher or lower claims limit or a higher or lower deductible than we would be subject to under our policy with the insolvent insurer.

We propose the definition set out below, which is consistent with the definition approved by the AER in in our 2021–26 distribution determination and in other recent distribution determinations.[13]

PROPOSED DEFINITION: INSURER CREDIT RISK EVENT

[13] See, for example, Attachment 15 of Ausgrid's Distribution Determination 2024 – 2029 and Attachment 15 of Endeavour Energy's Distribution Determination 2024 – 2029.

An insurer credit risk event occurs if an insurer of CitiPower's becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, CitiPower:

(a) is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or
(b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note: in assessing an insurer's credit risk pass through application, the AER will have regard to, among other things:

i. CitiPower's attempts to mitigate and prevent the event from occurring, by reviewing and considering the insurer's track record, size, credit rating and reputation; and
ii. in the event that a claim would have been covered by the insolvent insurer's policy, whether CitiPower had reasonable opportunity to insure the risk with a different provider.

In recent regulatory decisions, the AER has concluded that, while a distributor can take some steps to reduce its exposure to this event, expenditure beyond a certain level aimed at completely eliminating the risk is likely to be imprudent and inefficient, and in that context, sharing the risk between the distributor and its customers is more likely to be in the long-term interests of consumers with respect to price.[14]

In line with the AER's conclusion above, we take a number of steps to reduce our exposure to an insurer credit risk event, outlined below. Nonetheless, we consider inclusion of this event is appropriate and in the long term interests of consumers by removing the need for them to fund this event before it actually occurs.

We have a number of mitigation strategies in place to prevent us from being in a situation where one of our insurers becomes insolvent. In particular, we seek to mitigate the risk of any of our insurers becoming non-viable by regularly reviewing and reporting on each insurer's Standard & Poor (S&P) or equivalent credit rating movements.

Our minimum acceptable insurer S&P risk rating is A minus. If an insurer rating falls below the S&P A minus or equivalent other rating, our Risk Management & Compliance Committee has the discretion to:

- approve continued use of an insurer that does not have an A minus or higher rating. The decision to do this is only taken after consideration of financial analysis, which includes but is not limited to, the size of paid up capital and shareholder funds, amount of gross reinsurance and quality of the reinsurance; or

- move away from an insurer that falls below the A minus rating. In doing so, a remedial strategy is prepared and reviewed/approved by our CEO, which outlines timing associated with moving away from the insurer in question. The objective is to move away from the insurer as quickly as possible.

In addition, for selected key policies such as General Liability insurance, we take out insurance with multiple insurers, therefore spreading the risk and minimising reliance on any one insurer. Accordingly, the risk of one of our insurers becoming insolvent is very low, but nonetheless, not improbable.

[14] See, for example, Attachment 15 of Ausgrid's Draft Distribution Determination 2024 – 2029, p. 7 and Attachment 15 of Endeavour Energy's Draft Distribution Determination 2024 – 2029, p. 7.

Insurers can still fail regardless of how prudently they were chosen. For example, HIH Insurance was placed into liquidation in 2001, and AIG faced a liquidity crisis during the global financial crisis. While such events are infrequent, they can occur and the risk of an insurer failing is beyond our control.

Insurer's credit risk event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations, evidenced by the AER's prior acceptance of this event in our and other distributors' determinations. This is because:

- the event is not covered by a category of pass through event specified in the NER;
- the nature or type of event can be clearly identified at the time of our distribution determination, as evidenced by the AER having previously included this event in our 2011–2015, 2016–2020 and 2021–26 determinations, and more recent regulatory determinations;
- while we take all prudent steps to assess the viability of actual and potential insurers and to use only those providers that are expected to have the capacity to satisfy any claims under a policy (as discussed above), we could not reasonably prevent the occurrence of an insurer's credit risk event or substantially mitigate the cost impact;[15] and
- we have not identified insurance for insurer credit risk failure available on reasonable commercial terms and, due to the low probability of the event occurring, it is not possible to calculate a self-insurance premium.

In recent regulatory decisions, the AER has accepted that the insurer credit risk is not covered by any existing pass through event, the nature of the event is clearly identifiable at the time of the determination, and a prudent service provider could not reasonably prevent an event of that nature or type form occurring or substantially mitigate its cost impact, and could not insure (or self-insure) against the event.[16]

We consider that the proposed insurer credit risk event is consistent with the NEO and the revenue and pricing principles, as it:

- ensures that we are not placed in a position where we are unable to mitigate or avoid the event, or its cost impact, without incurring imprudent or inefficient expenditure; and
- provides us with a reasonable opportunity to recover our efficient costs.

Further, the inclusion of this event in our proposal means that consumers only bear the burden of such an event, if the event actually occurs (to the satisfaction of the pass-through provisions), rather than funding excessive and potentially unnecessary premiums. The acceptance of the event therefore provides for an appropriate sharing of risk between us and our customers, and is more likely to be in the long-term interests of consumers with respect to price.

2.3.2 Insurance coverage event

We have included an insurer coverage event in our 2026-31 regulatory proposal, consistent with our 2021-26 determination, which would allow us, subject to the AER's approval, to recover material costs that are incurred above our insurance policy limit or which otherwise fall outside the scope of cover under our insurance policies.

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15 AER, Draft decision Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 725.

16 See, for example, Attachment 15 of Ausgrid's Distribution Determination 2024 – 2029, p. 7 and Attachment 15 of Endeavour Energy's Distribution Determination 2024 – 2029, p. 7.

We consider that the most efficient and appropriate means of managing our exposure to the risk of incurring liabilities and costs beyond our insurance policy or scope of cover is via the pass through mechanism. This nominated pass through event allows us to recover material costs beyond the policy limit, or which otherwise fall outside the scope of the cover provided under the relevant insurance policy or policies. It would protect us from high cost impact events which would be uneconomical to insure, while benefitting consumers as they are not required to fund excessive premiums. Consumers only bear the risk of the insurance coverage event if the event occurs. The event therefore provides for an appropriate sharing of risk between us and our customers and is more likely to be in the long-term interests of consumers with respect to price.

We propose the definition set out below, which is consistent with the AER's Guidance Note on the Insurance Coverage Pass Through Event, and our 2021–26 determination and more recent regulatory determinations.[17]

PROPOSED DEFINITION: INSURANCE COVERAGE EVENT

An insurance coverage event occurs if:

1. CitiPower:
   a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or
   b) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and
2. CitiPower incurs costs:
   a) beyond a policy limit for the relevant insurance policy or set of insurance policies; or
   b) that are unrecoverable under the relevant insurance policy or set of insurance policies due to changed circumstances; and
3. The costs referred to in paragraph 2 above materially increase the costs to CitiPower in providing direct control services.

For the purpose of this insurance coverage event:

'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of CitiPower, where those movements mean that it is no longer possible for CitiPower to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies.

'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:

i. the limit not been exhausted; or
ii. those costs not been unrecoverable due to changed circumstances.

A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which CitiPower was regulated

CitiPower will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of CitiPower in relation to any aspect of CitiPower's network or business; and

[17] AER, Final guidance note – Insurance coverage pass through event, July 2021; see, for example, Attachment 15 of Ausgrid's Draft Distribution Determination 2024 – 2029, p. 7 and Attachment 15 of Endeavour Energy's Draft Distribution Determination 2024 – 2029, p. 7.

CitiPower will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of CitiPower in relation to any aspect of CitiPower's network or business.

Note for the avoidance of doubt, in assessing an insurance coverage event through application under rule 6.6.1(i), the AER will have regard to:

i. the relevant insurance policy or set of insurance policies for the event;
ii. the level of insurance that an efficient and prudent distributor would obtain, or would have sought to obtain, in respect of the event;
iii. any information provided by CitiPower to the AER about CitiPower's actions and processes; and
iv. any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event.

Insurance coverage event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations, evidenced by the AER's inclusion of this event in our 2021- 2026 determination and more recent regulatory determinations.[18] This is because:

- the event is not covered by a category of pass through event specified in the NER;
- the nature or type of event can be clearly identified at the time of determination, as evidenced by the AER having previously included this event in our 2021–26 distribution determination, and more recent regulatory determinations;
- the extent to which we can reasonably prevent a claim occurring which exceeds the limits and scope of our efficiently acquired insurance cover, or can take steps to mitigate incurring costs beyond the limits and scope of our efficiently acquired cover, is limited;
- we have obtained efficient levels of insurance cover which are commensurate with an assessment of our business risk. However, the efficient level and scope of such insurance is typically determined based on global market insurance conditions, with the level and scope of cover beyond the efficient coverage typically requiring exorbitantly higher and uneconomic premiums; and
- including an insurance coverage event as a pass through event represents a more appropriate means for managing our risk exposure to such an event than self-insurance given:
  - the complexity associated with developing credible self-insured risk quantifications for very low probability events, such as those that are beyond the existing liability limits and scope of our efficiently acquired cover;
  - that such an event is likely to be catastrophic in nature and have a significant financial impact on us.

The proposed nominated pass through event is consistent with the NEO and the revenue and pricing principles. This nominated pass through event would protect us from high cost and impact events that are uneconomical, and not prudent or efficient, to insure against. It ensures we are not placed in a position where we are unable to mitigate or avoid the event or its cost impact, without incurring imprudent or inefficient expenditure, and provides a reasonable opportunity for us to recover our efficient costs.

18 See, for example, Attachment 15 of Ausgrid's Draft Distribution Determination 2024 – 2029, p. 7 and Attachment 15 of Endeavour Energy's Draft Distribution Determination 2024 – 2029, p. 7.

Consumers benefit from the inclusion of this event because they are not required to fund excessive insurance premiums where insurance is available. Further, consumers only bear the risk of our insurance coverage event should such an event occur and satisfy the provisions for the approval of pass through amounts. The event therefore provides for an appropriate sharing of risk between us and our customers, and is more likely to be in the long-term interests of consumers with respect to price.

2.3.3 Natural disaster event

We have included a natural disaster event in our 2026-31 regulatory proposal, consistent with our 2021-26 determination, which would allow us, subject to the AER's approval, to pass through changes in our costs of providing direct control services that occur as a result of a natural disaster.

The occurrence of natural disasters such as floods, earthquakes, and major storms is entirely beyond our control. The timing of such an event cannot be determined in advance. Costs incurred as a result of a natural disaster depend on several variables, such as the type of event, the magnitude of the event, and the areas of the distributor's network which are affected (and the extent to which they are affected). Natural disasters are likely to be of a high magnitude or potentially even catastrophic. We are unable to obtain insurance on reasonable commercial terms, or self-insure, for all costs associated with these events.

We propose the definition set out below, which is consistent with the definition included in our 2021-26 determination and other recent AER determinations. [19]

PROPOSED DEFINITION: NATURAL DISASTER EVENT

Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2026–31 regulatory control period that changes the costs to CitiPower in providing direct control services, provided the cyclone, fire, flood earthquake or other event was:

a) A consequence of an act or omission that was necessary for the service provider to comply with a regulatory obligation or requirement with an applicable regulatory instrument; or

b) Not a consequence of any other act or omission of the service provider.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

(1) whether CitiPower has insurance against the event;

(2) the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

Natural disaster event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations because:

- the event is not covered by a category of pass through event specified in the NER;
- the nature or type of the event can be clearly identified at the time of our determination, as evidenced by the fact that the AER included this event in our 2011-15, 2016-20 and 2021-26 distribution determinations and more recent AER determinations;
- while we have in place a number of preventative measures of the kind detailed below, we cannot reasonably prevent an event of the requisite nature or type from occurring:

[19] See, for example, Attachment 15 of Ausgrid's Draft Distribution Determination 2024 – 2029, p. 7 and Attachment 15 of Endeavour Energy's Draft Distribution Determination 2024 – 2029, p. 7.

- ◦ an 'Enterprise Risk Management' approach is used to provide a comprehensive and consistent means to manage and report on business risk exposures through identification of strategic and operational risks, determining accountability for those risks, assessment of controls and the control environment and ensuring that there are adequate resources to manage the risks;
  - ◦ we conduct an annual risk profiling exercise, which results in a detailed risk register and risk profile. The risk assessment process is the foundation that enables us to maintain a dynamic risk management system tailored to our requirements. Risks in the risk register are clearly defined as to the event, causes and consequences. Controls applying to a particular risk are then rated on their effectiveness and reliance on the control to manage the risk. Each risk is then assessed for its inherent (without controls) and residual (with controls applied) risk rating. The risk rating is then assessed for acceptability and additional actions determined in accordance with the residual risk rating;
  - ◦ we have a duty under the Electricity Safety Act 1998 (Vic) to design, construct, operate, maintain and decommission our supply network to minimise, as far as practicable, the hazards and risks to the safety of any person, or of damage to the property of any person, arising from the supply network, and the bushfire danger arising from the supply network;
  - ◦ an electricity safety management scheme (ESMS) must be submitted to Energy Safe Victoria (ESV) for our supply network under the Electricity Safety Act 1998 (Vic). We must comply with the accepted ESMS, which also must include a plan for the mitigation of bushfire danger in relation to our supply network. The bushfire mitigation strategy plan (BMP) is published on our website;[20]
  - ◦ in the event of a natural disaster, we have in place a Crisis and Emergency Management System which provides an effective state of readiness to prepare for, respond to and recover from a range of credible and potential events, with the aim of mitigating the effects of the event as far as practicable;
- efficient levels of commercial insurance cover have been obtained, through our Industrial Special Risks insurance policy, which are commensurate with an assessment of our business risk arising from natural disasters. However, this insurance would likely not cover all costs associated with a natural disaster event and taking out further insurance would likely be inefficient and result in unnecessary cost increases to customers;
- including natural disasters as a pass through event represents a more efficient means for managing our risk exposure than self-insurance, given the complexity associated with developing credible self-insured risk quantifications for very low probability events, and our likely inability to pool enough risk to cover the cost impacts of a major natural disaster.

The AER has accepted that the natural disaster event is not covered by any existing category of pass through event, the nature of the event is clearly identifiable at the time of the determination and a prudent service provider could not reasonably prevent an event of that nature or type from occurring or substantially mitigate its cost impact, and could not insure (or self-insure) against the event.[21]

The inclusion of a natural disaster pass through event means that consumers only bear the risk should such an event occur and satisfy the provisions for the approval of pass through amounts, rather than funding excessive and potentially unnecessary insurance premiums. The event therefore provides for an appropriate sharing of risk between us and our customers, and is more likely to be in the long-term interests of consumers with respect to price.

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20 See Powercor, Bushfire Mitigation Plan, 2023.

21 See, for example, Attachment 15 of Powercor's 2021–26 Distribution Determination; Attachment 15 of CitiPower's 2021 – 2025 Distribution Determination; and Attachment 15 of United Energy's 2021–26 Distribution Determination`.

The proposed nominated pass through event is consistent with the NEO and the revenue and pricing principles, because it:

- ensures we are not placed in a position where we are unable to mitigate or avoid the event or its cost impact, without incurring imprudent or inefficient expenditure; and
- provides us with a reasonable opportunity to recover our efficient costs.

2.3.4 Terrorism event

We have included a terrorism event in our 2026-31 regulatory proposal, consistent with our 2021-26 determination. This event is designed to allow us, with the AER's approval, to pass through any changes to our costs of providing direct control services as a result of a terrorism event.

This event was included by the AER in our 2016-20 and 2021-26 distribution determinations and has also been included in more recent distribution determinations.[22]

While we have in place systems to mitigate the risk of a terrorism event occurring, we cannot completely eliminate the risk of such an event occurring.

PROPOSED DEFINITION: TERRORISM EVENT

Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:

a) from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and
b) changes the costs to CitiPower in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

i. whether CitiPower has insurance against the event;
ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and
iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

Terrorism event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations because:

- the event is not covered by another category of pass through event specified in the NER;
- the nature or type of event can be clearly identified at the time of our determination, as evidenced by this event being included in our 2016–20 and 2021–26 distribution determinations;
- our ability to reasonably prevent a terrorism event from occurring, or substantially mitigate the cost impact of such an event, is limited. While the occurrence of a terrorism vent is largely beyond our control, we undertake a range of measures to reduce the likelihood of a terrorism event. We continue to review and assess the level of security at our sites, in addition to undertaking security

[22] See, for example, Attachment 15 of Ausgrid's Distribution Determination 2024 – 2029 and Attachment 15 of Endeavour Energy's Distribution Determination 2024 – 2029.

surveys. We also interact with a range of organisations, and participate in various groups, including:

  - the Australian Security Intelligence Organisation (ASIO) Business Liaison Unit;
  - the Australian Cyber Security Centre;
  - the Trusted Information Sharing Network (TISN) through the Attorney-General's Department;
  - the Critical Infrastructure Program for Modelling and Analysis (CIPMA), also through the Attorney-General's Department;
  - Victorian Energy Security and Continuity Network (SCN);
  - AEMO's Victorian Electricity Emergency Committee (VEEC); and
  - the Distribution Business Information Sharing Security group.

- generally, the commercial market for insurance in Australia is insufficient to cover demand. While the Australian Government found in its 2012 Terrorism Insurance Act Review that the availability for insurance for terrorism is increasing, it nonetheless concludes that insurance for terrorism events remains insufficiently available at affordable rates:[23]

  > *…some commercial market capacity for terrorism insurance is re-emerging both internationally and domestically, although it remains insufficient to cover the available demand and is concentrated in supporting national pooled arrangements. Furthermore, there is insufficient capacity at reasonable prices for individual risks in Australia with the quantum of commercial market capacity being significantly below the current $13.4 billion scheme operated by the ARPC [Australian Reinsurance Pool Corporation].*

- our Industrial Special Risks insurance policy covers property damage and business interruption for terrorism, however it may not cover all of the impacts of a terrorism event on our network and business. Taking out further insurance would likely be inefficient given prevailing market conditions;
- self-insurance would not be a credible option because the relative infrequency and potentially high costs associated with terrorism events create significant challenges for self-insurance for this type of risk, and there is limited data on which to calculate a credible self-insurance premium.

In recent regulatory decisions, the AER has accepted that the terrorism event is not covered by any existing category of pass through event, the nature of the event is clearly identifiable at the time of the determination, and a prudent service provider could not reasonably prevent an event of that nature or type from occurring or substantially mitigate its cost impact, and could not insure (or self-insure) against the event.[24]

The proposed nominated pass through event is consistent with the NEO and the revenue and pricing principles because it:

- ensures that we are not placed in a position where we are unable to mitigate or avoid the event or its cost impact, without incurring imprudent or inefficient expenditure; and
- provides us with a reasonable opportunity to recover our efficient costs.

Further, the inclusion of a terrorism pass through event means consumers only bear the risk of such an event should the event occur and satisfy the provisions for the approval of pass through amounts,

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[23] Australian Government, *Terrorism Insurance Act Review: 2012,* p.2.

[24] See, for example, Attachment 15 of Ausgrid's Distribution Determination 2024 – 2029 and Attachment 15 of Endeavour Energy's Distribution Determination 2024 – 2029.

rather than funding excessive and potentially unnecessary insurance premiums. The event therefore provides for an appropriate sharing of risk between us and our customers, and is more likely to be in the long-term interests of consumers with respect to price.

2.3.5 Retailer insolvency event

We have included a retail insolvency event in our 2026-31 regulatory proposal, consistent with our 2021-26 determination. While clause 6.6.1(a1)(4) specifies a retailer insolvency event as a pass through event, the AER has acknowledged that this event does not apply to Victorian distributors and has considered it appropriate to provide equivalent protection to Victorian distributors through a nominated pass through event.[25]

This event was included by the AER in our 201620 and 202126 distribution determinations, as well as the distribution determinations of other Victorian distributors for those periods.[26]

The retailer insolvency event in clause 6.6.1(a1)(4) of the NER does not apply in Victoria, because:

- that pass through event was initially introduced into the NER through the National Electricity (National Energy Retail Law) Amendment Rule 2012 (NERL Amendment Rule);
- the NERL Amendment Rule purports to only apply to jurisdictions that have implemented the National Energy Retail Law (NERL);
- the National Energy Customer Framework (NECF) (which encompasses the National Energy Retail Law) has not been adopted in Victoria, with the exception of Chapter 5A of the Rules and the provisions providing for the retailer of last resort arrangements (introduced in Victoria by the National Energy Retail Law (Victoria) Act 2024).

PROPOSED DEFINITION: RETAILER INSOLVENCY EVENT

Until such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria, retailer insolvency event has the meaning set out in the NER as in force from time to time, except that:

a) where used in the definition of 'retailer insolvency event' in the NER, the term 'retailer' means the holder of a licence to sell electricity under the Electricity Industry Act 2000 (Vic); and
b) other terms used in the definition of 'retailer insolvency event' in the NER as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the NER or National Energy Retail Law not in force in Victoria, take their ordinary and natural meaning, or their technical meaning (as the case may be).

For the purposes of this definition, the terms 'eligible pass through amount' and 'positive change event' where they appear in the NER (as well as any subordinate terms including, without limitation, 'retailer insolvency costs', 'failed retailer' and 'billed but unpaid charges') are modified in respect of this retailer insolvency event in the same manner as those terms are modified in respect of the 'retailer insolvency event' prescribed in the NER from time to time.

Note: This retailer insolvency event will cease to apply as a nominated pass through event on commencement of the National Energy Consumer Framework in Victoria.

[25] AER, Powercor, Preliminary decision, Powercor Distribution Determination 2016 to 2020, Attachment 15 – Pass through events, October 2015, pp. 15-21.
[26] See AusNet and Jemena's 2021–26 Distribution Determinations.

Retailer insolvency event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations because:

- the event is not covered by another category of pass through event specified in the NER, as recognised by the AER in its observation that the event specified in clause 6.6.1(a1)(4) does not apply in Victoria;
- the nature or type of event can be clearly identified at the time of the determination for the distributor, as it is based on the 'retailer insolvency event' in the NER;
- similar to distributors in jurisdictions which have wholly adopted the NECF, we are unable to manage the risk of retailers defaulting on payment of our network charges and, as such, are unable to reasonably prevent a retailer failure event from occurring, or substantially mitigate the cost impact of such an event;
- due to the low probability, but potentially high cost, of a retailer failure event occurring, it is inefficient for us to insure (either externally or self-insure) against this event.

The proposed nominated pass through event is consistent with the NEO and the revenue and pricing principles because it provides us with a reasonable opportunity to recover our efficient costs and avoids placing us in a position where we incur costs that we are unable to avoid, recover or mitigate. The existing credit support arrangements for us for failure of a retailer do not recover the full amount of the outstanding debt to us, and this shortfall in cost recovery can be significant.

The costs to us of a retailer failure which fall within the proposed definition of the retailer insolvency event, and satisfy the provisions for the approval of pass through amounts, should be borne by consumers because:

- the costs of retail contestability should be borne by the beneficiaries of that contestability, that is, by consumers;
- consumers are the most appropriate party to bear the costs of the financial failure of a retailer because we are unable to manage the risk of a retailer failure, and they are also better placed to bear these costs as they can be spread across a diversified consumer base.

The event therefore provides for an appropriate sharing of risk between us and our customers, and is more likely to be in the long-term interests of consumers with respect to price.

2.3.6 Fault level event

We have included a fault level event in our 2026-31 regulatory proposal. This is an additional nominated pass through event that we have not previously proposed to the AER.

As part of our network planning responsibility, we must ensure that short circuit levels at all zone substations, and the 66kV buses of the connection assets, remain within the fault level limits set out in the Electricity Distribution Code of Practice (EDCoP) and our connection agreements with our customers within which facilities connected to our network are required to operate, as well as the Primary or Secondary Plant Limitations (Plant) for each zone substation and bus.

The relevant fault levels for facilities connected to our network (i.e. either the EDCOP limit or the Plant limit), as set out in our connection agreements, should be considered the 'design fault levels' for the purposes of clause 5.13.1 of the NER. The NER defines design fault level as "the maximum level of fault current that a facility can sustain while maintaining operation at an acceptable performance standard." The performance standards specified in our connection agreements are such standards, with the result that the maximum level of fault they specify are 'design fault levels'.

We have obligations to keep fault levels below specified limits

Clause 5.13.1(d)(2)(iv) and (3) of the NER imposes obligations on us, as part of our distribution annual planning review, to identify any limitations on our network caused by (among other factors) design fault levels being exceeded. If we identify any such network limitation, we must identify whether corrective action is required to address this limitation. When the design fault levels will be exceeded (in the absence of corrective action), this will result in a network limitation that must be addressed, in order to discharge our statutory obligation under clause 5.13.1(d)(2)(iv) and (3), as our network will likely be damaged if the design fault levels are exceeded. Put simply, the NER requires us to plan, operate and maintain our network so as to avoid the exceedance of the fault level limits specified by the EDCOP and relevant Plant limits.

Clause 21.9 of the EDCoP requires an embedded generator to design and operate its embedded generating unit so that it does not cause fault levels in the distribution system to exceed the levels specified in Table 6 of the EDCoP. While clause 21.9 imposes a requirement on embedded generators rather than us, good electricity industry practice is that we must ensure our network does not exceed the levels set out in Table 6 of the EDCOP (with limited exceptions). There is an implied obligation on distributors to maintain and operate their systems so as to ensure fault levels on systems don't exceed the levels specified in Table 6. This is to ensure that our customers can safely connect to our distribution network, and that we operate our network in a manner that minimises the risk of damage to plant (both our plant, and our customers' plant). Table 6 is replicated below.

DISTRIBUTION SYSTEM FAULT LEVELS		
Voltage Level kV	**System Fault Level**	**Short Circuit Level**
66	2500	21.9
22	500	13.1
11	350	18.4
6.6	250	21.9
<1	36	50.0

The EDCOP limits are generally reflected in our connection agreements with customers and as part of various generator performance standards. When negotiating a connection with a customer, we nominate the fault level that the customer's plant must be able to withstand. If fault levels on the relevant part of our network exceed this specified level, our customer's plant could suffer catastrophic damage, as well as posing a significant safety risk to personnel in the area. In nominating this fault level and requiring our customers to confirm their plant can withstand that level, we are subject to an implied contractual obligation committing us to operating the relevant part of our network at a fault level below that specified in the agreement.

The Plant limit is the maximum short-circuit current that a piece of equipment can safely interrupt (i.e. break rating) or safely withstand (i.e. withstand rating). These limits are retrieved from Zone Substation Plant Data Sheets or advised by the Plant and Stations team within the networks part of our business. Failure to maintain these levels within the limits may result in significant personnel safety risk or damage to our network in the event of a fault, which may require remedial action (e.g. rebuilding parts of the network) at significant cost.

If parts of our network are operating at fault levels above the lowest of the EDCOP levels, Plant limits or the level specified in our connection agreements, there is a real risk that our customers' property will suffer catastrophic damage. Additionally, this creates a significant safety risk for persons in the area.

As is evident from the discussion above, we are subject to a number of regulatory obligations that have the effect of requiring us to ensure that all parts of our network are operating within the applicable fault level limitations.

Fault levels are increasing as a result of new generation connections

In recent years, the number of areas on our network that are operating above, or approaching, their fault level limit has significantly increased.

This is primarily a result of the number of new generation projects AusNet and AEMO are connecting to the 220kV transmission network. The fault levels on our network will continue to rise throughout the 2026–31 regulatory period, as AEMO continues to connect renewable generation, other inverter based resources, as well as proceeding with its Victorian System Strength Project which will increase fault levels in areas of the network that have traditionally had low fault levels.

In October 2021, the Australian Energy Market Commission (AEMC) made a final rule determination on Efficient Management of System Strength on the Power System (System Strength Rule).[27] This rule was made in response to the challenges posed by the integration of renewable generation into the NEM, while coal-fired generators will progressively withdraw from the network. Historically, NEM system strength has been supplied as a by-product of synchronous generators, such as coal-fired generation. The uptake in renewable generation, which does not contribute to system strength, combined with the withdrawal of previous sources of system strength, has given rise to concerns around system strength in the NEM.

Under the System Strength Rule, AEMO Victorian Planning (AVP), the System Strength Service Provider for Victoria, is responsible for provision of system strength services, to ensure power system stability and to facilitate efficient generator and storage connections.[28] AVP is undertaking a regulatory investment test for transmission (RIT-T) to address the identified need for sufficient system strength services to ensure the system strength standard as per S5.1.14 of the NER is met for both forecast minimum demand and efficient levels at each of the Victorian system strength nodes from 2 December 2025 onwards.[29] Some of the options set out in AEMO's Project Specific Consultation Report involve deployment of equipment that, while improving system strength, would result in higher fault levels on some areas of our network.

Different areas of our network have been designed to manage different fault levels, depending on the historical generation load in each area. Generation in Victoria has traditionally occurred in discrete areas, such as the Latrobe Valley, using 'rotating' plant that contribute increased fault current to the network. The parts of our network that service these historically generation-heavy areas are designed to withstand greater fault levels, as those areas must manage the fault levels contributed by the rotating generators. Other parts of our network have been designed to manage lower fault levels, as they did not have to withstand the fault level contributions from generators.

AEMO is proposing to install synchronous condensers to assist with system strength issues. Synchronous condensers contribute similar fault levels to the network as traditional generation sources, due to their rotating nature. While these synchronous condensers will assist with overall system strength, AEMO is proposing to install them in areas of our distribution network that have not historically been designed to manage the fault level they will contribute. Further, as renewable

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27 AEMC, *Rule Determination: National Electricity Amendment (Efficient Management of System Strength on the Power System) Rule 2021*, 21 October 2021.

28 AVP, Victorian System Strength Requirement, Regulatory Investment Test for Transmission, Project Specific Consultation Report, July 2023, p. 3.

29 AVP, Victorian System Strength Requirement, Regulatory Investment Test for Transmission, Project Specific Consultation Report, July 2023, p. 3.

generation is connected to the areas of our network with lower fault level limitations, these parts of the network will begin to operate at fault levels above the amount they have been designed to withstand.

There is a real risk that the connection of either synchronous condensers or new generation, to a part of the 220kV transmission network that supplies electricity to our network, will increase the fault level on an area of our network, to the extent that those areas of our network exceed their applicable fault level limit. This will mean that we are in breach of our regulatory obligations, as well as having significant safety risks for our staff and customers, and of damage to our own system and customer facilities connected to our network.

As we do not have full visibility of all impending transmission connections we are not able to pinpoint exact locations on our network that are most at risk. However, we would like to ensure that we can take the required corrective action if a transmission connection causes an area of our network to begin operating at fault levels above the limits applicable to that part of the network. Accordingly, we propose including a fault level pass through event in our 2026-31 distribution determination, to enable us to recover the prudent and efficient costs of the works required to correct a fault level exceedance.

We consider this is more appropriately treated as a pass through event, rather than a contingent project, as:

- these risks are relevant to all Victorian distributors, rather than just one business;
- multiple areas of our network are at risk, rather than one specific location; and
- there is no one particular upcoming transmission connection that would cause a part of our network to exceed regulated or Plant fault level limits, rather, such a connection is unforeseeable and could occur at any time, as we do not have full visibility over the connections of new generation that AusNet and AEMO may progress in the near term or the balance of the 2026–31 regulatory period.

PROPOSED DEFINITION: FAULT LEVEL EVENT

A fault level event occurs if a transmission connection agreement for the connection of a new generating system, integrated resource system or synchronous condenser to the Victorian declared transmission system is entered into, which:

- will cause a part or parts of our distribution network to operate at fault levels exceeding the lower of:
    - the levels set out in Table 6 of the EDCoP, as applicable to the relevant part of the network based on its voltage level; or
    - the relevant Plant Limit; and
- increases CitiPower's costs of providing direct control services.

For the purposes of this fault level event:

'EDCoP' means the Victorian Electricity Distribution Code of Practice made by the Essential Services Commission Victoria under the Essential Services Commission Act 2001;

'Plant Limits' means the Primary or Secondary Plant Limitation, retrieved from Zone Substation Plant Data Sheets or advised by the Plant and Stations team within the networks part of our business.

Fault level event satisfies nominated pass through considerations

This event is consistent with the nominated pass through event considerations because:

- the event is not covered by a category of pass through event specified in clause 6.6.1(a1) to (4) of the NER;

- the nature and type of event is clearly defined;
- the event is wholly beyond our control – we cannot prevent AusNet and AEMO from connecting new resources to the transmission network that result in an increase in the fault levels on our network, nor can we foresee such connections as they are to the transmission network and we are not provided with full visibility over impending connections of this kind; and
- we cannot insure against the event, nor are we able to self-insure.

The proposed nominated pass through event is consistent with NEO and the revenue and pricing principles, as it will promote efficient investment in electricity services for the long term interests of electricity consumers with respect to the quality, safety, reliability and security of supply of electricity. By including this event as a pass through event, we are ensuring that consumers only bear the costs associated with the event, if a resource is connected to the 220kV transmission network that will cause a part or parts of our distribution network to operate at fault levels above the limits set out in Table 6 of the EDCoP, our connections agreements with customers, or the Plant Limits, as relevant.

2.3.7 Electrification event

We have included a fault level event in our 2026-31 regulatory proposal. This is an additional nominated pass through event that we have not previously proposed to the AER.

We consider inclusion of the electrification event is necessary to deal with the uncertainty resulting from the energy transition, particularly in respect of the timing and pace at which electrification will occur.

Given the large amount of uncertainty attached to the energy transition we consider that there is a possibility that Victorian consumers may significantly change their energy consumption habits during the 2026-31 regulatory period, both on a proactive basis and as a result of government announcements and policies. Victorian households and businesses are likely to become increasingly electrified, moving away from gas powered appliances to full electrification. This shift will result in a significant increase in electricity consumption on our distribution network, at a speed above typical organic growth levels, as consumers move as one in response to government policy signals and requirements.

The Victorian Government has ambitious emissions reduction targets of 45–50% by 2023, 75–80% by 2035, and net zero by 2045. Achieving these targets will require significant change in energy consumption, particularly given Victoria's comparatively heavy reliance on gas (~3 times more MJ consumed per annum than NSW and South Australia, ~7 times more than Queensland and ~1.5 times more than ACT and Tasmania combined).[30] The Victorian Government has already announced and introduced some restrictions on the use of natural gas and moves towards electrification, including:

- amendment VC250 to the Victorian Planning Provisions to phase out new gas connections for new dwellings, apartment buildings and residential subdivisions;[31]
- an amendment to the Building Act 1993 to give the Governor in Council a power to make regulations prohibiting new gas connections, or modifications of existing gas connections, to existing building;[32]
- a Building Electrification Regulatory Impact Statement (RIS), which sets out options for driving greater electrification of buildings in Victoria, with a preferred option involving electrification of all

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[30] Frontier Economics, Residential Energy Consumption Benchmarks – Final Report for the Australian Energy Regulator, 9 December 2020, p. 27.
[31] Victoria Government Gazette, *No. S 1 Monday 1 January 2024*.
[32] Building Legislation Amendment and Other Matters Bill 2024.

existing residential gas hot water and heating must be electrified through replacement at end of life and all new residential and commercial buildings must be built all-electric.[33]

These measures alone will already result in a significant increase in electrification in Victoria. The Victorian Government has observed that there are 50,000 new homes built in Victoria per year, with 40,000 of these connecting to the gas network. The additional electricity consumed by these 40,000 homes, who were previously using gas, will significantly increase demand on our network. Further, the Governor in Council can make regulations at any time to prohibit new gas connections or modifications of existing gas connections, and can make delegated legislation requiring Victorian households to cease using gas altogether.

Together, these existing and future measures will result in a significant increase in electrification, likely to occur at haste. The consumption and demand forecasts that underpin our regulatory proposal already reflect the impact of Amendment VC250. We have not included the impact of the other two developments in our consumption and demand forecasts, due to uncertainty of the timing and scope of any regulations made under the Building Act 1993 or options progressed pursuant to the Building Electrification RIS.

As we are unable to reflect all of these existing measures, and any future measures, in our expenditure forecasts for the 2026–31 regulatory period, we consider it is appropriate for us to account for future measures leading to increased electricity consumption via the pass through mechanism, rather than in our forecast capex. The increase in consumption and/or demand as a consequence of electrification, and the time and pace at which this increase occurs, are largely dependent on government announcements and policy, and cannot be easily predicted at this stage.

Our definition of the event refers to a government policy announcement, rather than the passage of new legislation or regulation. This is because consumers will begin to change their behaviour in response to government announcements, and in advance of actual legislative amendment. For example, if a consumer is installing a new hot water system and the Victorian Government has announced that it will seek to prohibit the use of gas hot water systems at some time in the next two years, the consumer is likely to install an electric hot water system, despite the fact that no legislative change has yet occurred.

Government policies, and the timeframes for implementing such policies, are difficult to predict with certainty, and we do not want consumers to bear the cost of increases in capex for electrification until we have certainty about the policies that will drive these increases and the increases we will actually incur. At the same time, the NEL recognises that we should have a reasonable opportunity to recover at least the efficient cost of providing services and complying with regulatory obligations. Including the electrification event in our distribution determination will allow us to recover the costs associated with increased electrification, while ensuring consumers only pay when this increase actually occurs.

The AER has recognised the importance of balancing affordability with necessary expenditure required to support the energy transition in its distribution determinations, noting that it supports the need for innovative approaches to help drive an affordable energy transition.[34] We consider that the inclusion of the electrification event strikes the desired balance and ensures consumers only pay for the costs of electrification as they become known with certainty, so assisting to deliver an affordable energy transition.

We propose the definition set out below.

PROPOSED DEFINITION: ELECTRIFICATION EVENT

33 Department of Transport and Planning, *Building Electrification Regulatory Impact Statement*, December 2024.

34 AER, Draft Decision – Evoenergy Electricity Distribution Determination 2024 – 2029, Overview, September 2023, p. v.

An electrification event occurs if:

1. The Commonwealth Government or the Government of Victoria announces a new or amended policy, program, initiative, scheme or other measure, which is directed at accelerating electrification of transport, or gas-powered appliances or processes; and
2. The cost to CitiPower to meet or manage the actual or expected demand materially increases as a result of the announcement, relative to the cost set out in CitiPower's 2026-2031 regulatory proposal.

In assessing an electrification event, the AER will have regard to whether, as a result of the announcement, there is:

(a) a forecast increase in energy used by customers connected to CitiPower's electricity distribution network, when compared to the forecasts set out in our 2026-31 regulatory proposal; or

(b) an increase in the after diversity maximum demand (ADMD) applicable at the date we submit our regulatory proposal to the AER.

For the purposes of this event, 'after diversity maximum demand' or 'ADMD' means the maximum demand that our electricity distribution network is capable of supplying in a particular area, expressed as an average per dwelling and set out in our technical standard DA411.

The electrification event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations because:

- the event is not covered by a category of pass through event specified in clause 6.6.1(a1) to (4) of the NER. In particular, it is not covered by the regulatory change event, as the electrification event will occur before regulatory change is implemented – a government announcement is sufficient, which is not the case for the regulatory change event;
- the nature and type of event is clearly defined;
- the event is beyond our control and entirely in the hands of the Victorian Government; and
- we cannot insure against the event.

We consider that the electrification event is consistent with the NEO and the revenue and pricing principles, including because:

- the NEO includes "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity with respect to…the achievement of targets set by a participating jurisdiction for reducing Australia's greenhouse gas emissions or that are likely to contribute to reducing Australia's greenhouse gas emissions."[35]
- inclusion of the electrification event as a pass through event would promote efficient investment in electricity services for the long term interests of consumers with respect to achieving Victoria's emissions reduction targets, as it would ensure consumers are not paying for increased consumption and/or demand on the network until that increase actually occurs.
- the electrification event will provide us with a reasonable opportunity to recover the efficient costs we will inevitably incur when electrification happens, rather than leaving us to bear the cost of increased consumption and/or demand prompted by government electrification policies.

[35] NEL, section 7.

2.3.8 AEMO participant fee event

We have included an AEMO participant fee event in our 2026-31 regulatory proposal. This is an additional nominated pass through event that we have not previously proposed to the AER. We consider inclusion of this event is necessary to account for the uncertainty arising from the timing of AEMO's next participant fee review, which may result in the introduction of fees on distributors, but will not be finalised until after our distribution determination is finalised.

AEMO recovers its budgeted revenue requirements from NEM market participants. Under the NER, AEMO has the power to recover market fees from registered participants.[36] The NER requires AEMO to publish a structure setting out how its budgeted revenue is to be recovered through participant fees. AEMO determines the allocation of participant fees every five years, with the actual amounts charged determined on an annual basis, via the AEMO budgeting process.

AEMO's most recent determination of its electricity market participant fee structure was released in March 2021. In its draft determination, AEMO proposed introducing an allocation of its core NEM function costs to both TNSPs and distributors.[37] In its final determination, AEMO ultimately decided to include only TNSPs in this allocation, but indicated that it would monitor the extent of distributors' involvement with AEMO's systems and processes, and should there be a material increase in the level of that involvement, it would consider a declared NEM fee project consultation process to recover those costs from distributors.[38]

AEMO's next participant fee review is scheduled to commence in early 2025, ahead of a 1 July 2026 start. Our revised regulatory proposal is due to the AER in December 2025, which will not allow us to account for any fee imposed on us by AEMO in this determination. Given AEMO initially decided to impose charges on distributors in its last review, but ultimately decided to impose charges on TNSPs, we consider there is a real chance that we will be required to pay participant fees to AEMO, which are not built into our allowed revenues.

Additionally, the NER permits AEMO to determine a separate fee to recover the costs of specific projects (declared NEM projects) during the term of a participant fee structure determination.[39] Accordingly, AEMO could impose further fees on distributors in the 2026–31 regulatory period, in addition to any annual fees imposed in its 2025/2026 determination.

Our proposed definition, set out below, is intended to capture the fees that may be imposed by AEMO as part of its 2025/2026 participant fee review process, and any additional fees imposed in respect of a declared NEM project.

PROPOSED DEFINITION: AEMO PARTICIPANT FEE EVENT

An AEMO participant fee event occurs if:

1. during an AEMO Participant Fee Consultation process, including for a Declared NEM Project, AEMO determines that distributors are required to pay participant fees or increases the fees required to be paid by distributors; and
2. AEMO's determination will increase the cost of providing direct control services in the 2026–31 regulatory control period.

For the purposes of this definition:

[36] NER, clause 2.11.2.
[37] AEMO, Electricity Fee Structures – Draft Report and Determination, November 2020.
[38] AEMO, Electricity Fee Structures – Final Report and Determination, March 2021.
[39] NER, clause 2.11.1(bb).

'AEMO Participant Fee Consultation' means a consultation AEMO undertakes in accordance with clause 2.11 of the NER, and the corresponding determination.

'Declared NEM Project' has the meaning given to that term in the NER.

AEMO participant fee event satisfies nominated pass through event considerations

This event is consistent with the nominated pass through event considerations because:

- the AER has accepted that the event is not covered by a category of pass through event specified in clause 6.6.1(a1) to (4) of the NER, in its decision on TasNetworks' proposal of this event in its 2024-2029 determination, We acknowledge that there is some uncertainty as to whether the AEMO participant fee determination would be a service standard event or a regulatory change event, as it is unclear whether the participant fee event would have the consequences required by the definition of those events. To the extent the AER now considers the AEMO participant fee event would be or would likely be a service standard event or a regulatory change event, we acknowledge that the proposed nominated event is not required;
- the nature and type of event is clearly defined;
- the event is beyond our control and we cannot substantially mitigate the cost impacts of this type of event; and
- we cannot insure against the event.

The proposed nominated pass through event is consistent with the NEO and the revenue and pricing principles because it provides us with a reasonable opportunity to recover our efficient costs and avoids placing us in a position where we incur costs that we are unable to avoid, recover or mitigate. The fees imposed by AEMO would be imposed on us as a distributor, including because of the increased amount of AEMO's activities being undertaken for TNSPs and distributors, for example to manage power system security and power system reliability.[40] This is directly linked to our provision of direct control services, and is, accordingly, a cost incurred by us in providing direct control services.

40 AEMO, Electricity Fee Structures – Draft Report and Determination, November 2020, p. 23.

3. Contingent projects

3.1 Background

The NER provide for regulatory proposals to include proposed contingent capital expenditure which the distributor considers is reasonably required for the purpose of undertaking a proposed contingent project.[41] A contingent project is a project that is reasonably required to be undertaken, but which is excluded from a distributor's general capital expenditure allowance because of uncertainty about its requirement, timing or costs

3.2 Rule requirements

A regulatory proposal may include proposed contingent capital expenditure which the distributor considers is reasonably required for the purpose of undertaking a proposed contingent project. Clause S6.1.3(14) of the NER requires a distributor that is seeking a contingent project for the purposes of a relevant distribution determination to provide in its building block proposal:

- a description of the proposed contingent project, including the reasons the distributor considers the project should be accepted as a contingent project for the regulatory period;
- a forecast of the capital expenditure which the distributor considers is reasonably required for the purpose of undertaking the proposed contingent project;
- the methodology used for developing that forecast and the key assumptions that underlie it;
- information that demonstrates that the undertaking of the proposed contingent project is reasonably required in order to achieve one or more of the capital expenditure objectives;
- information that demonstrates that the proposed contingent capital expenditure for the proposed contingent project complies with the requirements set out in clause 6.6A.1(b)(2) (which are set out below); and
- the trigger events which are proposed in relation to the proposed contingent project and an explanation of how each of those conditions or events addresses the matters referred to in clause 6.6A.1(c) (which are set out below).

Our distribution determination for the 2026–31 regulatory period will be predicated on constituent decisions including the AER's determination in respect of:[42]

- whether each of the proposed contingent projects described in the current regulatory proposal are contingent projects for the purposes of the distribution determination, in which case the decision must clearly identify each of those contingent projects;
- the capital expenditure that it is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of each contingent project as described in the current regulatory proposal;
- the trigger events in relation to each contingent project (in which case the decision must clearly specify those trigger events); and
- if the AER determines that such a proposed contingent project is not a contingent project for the purposes of the distribution determination, its reasons for that conclusion, having regard to the requirements of clause 6.6A.1(b) (which are set out below).

41 NER, clause 6.6A.1.
42 NER, clause 6.12.1(4A).

The AER must determine that a proposed contingent project is a contingent project if it meets the criteria set out in clause 6.6A.1(b)(1) and (2), which are as follows:

- the contingent project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives;
- the proposed contingent capital expenditure:
  - is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure for the relevant regulatory period which is accepted in accordance with clause 6.5.7(c) or substituted in accordance with clause 6.12.1(3)(ii) (as the case may be);
  - reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of the proposed contingent project as described in the regulatory proposal; and
  - exceeds either $30 million or 5% of the value of the annual revenue requirement for the relevant distributor for the first year of the relevant regulatory period, whichever is the larger amount;
- the proposed contingent project and the proposed contingent capital expenditure, as described or set out in the regulatory proposal, and the information provided in relation to these matters, complies with the relevant requirements of any relevant regulatory information instrument; and
- the trigger events in relation to the proposed contingent project which are proposed by the distributor in its regulatory proposal are appropriate.

In determining whether a trigger event included by a distributor in its regulatory proposal is appropriate, clause 6.6A.1(c) requires that the AER have regard to the need for a trigger event to be:

- reasonably specific and capable of objective verification;
- a condition or event, which, if it occurs, makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives;
- a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole;
- described in such terms that the occurrence of that event or condition is all that is required for the distribution determination to be amended under clause 6.6A.2; and
- an event or condition, the occurrence of which is probable during the regulatory period, but the inclusion of capital expenditure in relation to it under clause 6.5.7 is not appropriate, because:
  - it is not sufficiently certain that the event or condition will occur during the regulatory period or if it may occur after that regulatory period or not at all; or
  - subject to the requirement to satisfy subparagraph (b)(2)(iii) (being the requirement that the proposed contingent capital expenditure exceed the larger of $30 million or 5% of the annual revenue requirement for the first regulatory year), the costs associated with the event of condition are not sufficiently certain.

Under clause 6.6A.2 of the NER, a distributor may apply to the AER during a regulatory period to amend a distribution determination that applies to that distributor where a trigger event for a contingent project in relation to that distribution determination, has occurred.

3.3 Our proposed contingent projects

3.3.1 LS Zone Substation Rebuild

DESCRIPTION	EXPENDITURE	TRIGGER
Rebuild of LS Zone Substation	$70 million	CitiPower: 1. prepares a business case and relevant regulatory investment test for distribution documentation, including a cost-benefit analysis that demonstrates that the Preferred Option is rebuilding the LS Zone Substation; and 2. obtains all relevant internal approvals to proceed with the project. For the purposes of this trigger: 'Regulatory investment test for distribution' has the meaning given to that term in the NER. 'Preferred Option' has the meaning given to that term in clause 5.10.2 of the NER.

Melbourne's Inner North was, up until 2023, mainly supplied by three zone substations, being Lauren Street (LS), Victoria Market (VM) and Bouverie Queen (BQ). However, the LS Zone Substation was decommissioned in 2023 when the West Melbourne Terminal Station 22kV sub-transmission network was abandoned. Load that was in the LS Zone Substation was transferred to the BQ and VM Zone Substations, which are currently serving ~20,000 and ~9,800 customers respectively.

The Inner North is currently experiencing a period of rapid growth, with the BQ Zone Substation forecast to add 8MVA of block loads and VM Zone Substation forecast to add 24MVA of block loads. Both the BQ and VM Zone Substations are forecast to exceed their summer and winter N-1 ratings in the 2026–31 regulatory periods, as discussed further in the associated business case.[43]

This growth will likely be accelerated with the construction of the Arden Precinct. The Arden Precinct is a 44 hectare urban renewal area located around the new Arden Station in North Melbourne. The Arden Precinct is intended to be an employment and living hub, projected to accommodate ~34,000 jobs and 15,000 residents. Arden Station is due to be completed in 2025, and the Victorian Government is moving forward in its progression of the Arden Precinct, having shortlisted four developers to partner with the Government for the delivery of the development.

The Arden Precinct is expected to add significant new demand to our network, in particular, to the BQ and VM Zone Substations, due to their proximity to the proposed development site of the Arden Precinct. However, the precise timing of this added demand is currently uncertain, and will depend on the pace of the Arden Precinct development and the level of load that the Precinct ultimately adds.

We have considered several options to meet the forecast demand in Inner North Melbourne, set out in the associated business case. The current preferred option (Option 2) is to install a third transformer at BQ Zone Substation, and to transfer loads from the VM Zone Substation to the BQ Zone Substation, while accommodating loads from the Arden Precinct at the BQ Zone Substation.

[43] CP BUS 3.02 – Bouverie Queensberry supply area – Jan2025 – Public

However, Option 2 may not be sufficient to address the capacity exceedance issues at the BQ and VM Zone Substations in the 2026–31 regulatory period, if the Arden Precinct adds additional demand to the network in that period. An additional option we have explored is the rebuilding of the LS Zone Substation with two 55MVA 66/11kV transformers, to accommodate the Arden Precinct loads. This option was not the preferred option for meeting overall forecast demand in Inner North Melbourne, including because it does not address the capacity exceedance issues at the BQ and VM Zone Substations, which are expected to be an issue even without the additional load from the development of the Arden Precinct. However, it is likely to be the most appropriate option to cater for the additional demand from the Arden Precinct, in combination with Option 2, if demand growth from the Precinct necessitates this.

As Option 2 is our preferred option and we are certain that this work will be necessary in the 2026-31 regulatory period, we are including the expenditure required for that option in our forecast capital expenditure. However, as the LS Zone Substation Rebuild is dependent on the timing and extent of load added by the Arden Precinct development, we consider it is more appropriate as a contingent project.

The LS Zone Substation Rebuild contingent project meets the NER requirements

In respect of the requirement in clause 6.6A.1(b)(1) of the NER, that the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives, we consider that the LS Zone Substation Rebuild contingent project will be required to meet or manage the current expected demand for standard control services, and to maintain the quality, reliability or security of supply of the distribution system and standard control services, over the 2026–31 regulatory period, having regard to the Victorian Government's plans to develop the Ardern Precinct.[44]

As explained further in the associated business case, the BQ and VM Zone Substations are forecast to exceed their summer and winter N-1 ratings in the 2026–31 regulatory period, even without the additional load of the Arden Precinct. We are proposing to install an additional transformer at the BQ Zone Substation to manage this demand, but further work will be required as the Arden Precinct progresses, as the additional load will put the existing BQ and ZN Zone Substations at risk. The LS Zone Substation Rebuild is required to manage the additional demand for standard control services that will result from the development of the Arden Precinct.

The LS Zone Substation Rebuild also meets the criteria set out in clause 6.6A.1(b)(2) of the NER, as the proposed contingent capital expenditure:

- is not otherwise provided for in the total of the forecast capital expenditure for the 2026–31 regulatory period. While the additional transformer at the BQ Zone Substation is included, that work does not form part of this contingent project. The forecast expenditure for the LS Zone Substation Rebuild is not included in our forecast capital expenditure;
- reasonably reflects the capital expenditure criteria in clause 6.5.7(c), taking into account the capital expenditure factors in clause 6.5.7(e);
- exceeds $30 million or five percent of the value of our proposed annual revenue requirement for the first year of the 2026–31 regulatory period, whichever is greater;
- there are no relevant regulatory information instrument requirements, other than a requirement that we list our proposed contingent projects in our reset regulatory information notice.

The trigger is appropriate, in accordance with clause 6.6A.1(c), as:

- it is reasonably specific and capable of objective verification. Cost-benefit analysis is commonly used by network service providers and is accepted as an appropriate tool for assessing whether a

44 NER, clause 6.5.7(a)(1) and (3).

network augmentation should proceed. Their objectivity is one of the reasons they are used so commonly by network service providers;

- it is an event, which, if it occurs makes the undertaking of the contingent project reasonably necessary in order to achieve the relevant capex objectives, in this instance being:
    - to meet or manage demand for standard control services; and
    - to maintain the quality, reliability and security of supply;
- the event will generate costs that relate to a specific location, being the Inner North Melbourne area served by the BQ and VM Zone Substations, including in particular the Ardern Precinct, rather than the distribution network as a whole;
- it is described in such a way that the occurrence of the event is all that is required for the distribution determination to be amended under clause 6.6A.2; and
- the occurrence of the event is probable during the 2026–31 regulatory period, but the inclusion of capital expenditure in relation to the event under clause 6.5.7 is not appropriate because the precise timing of the event will depend on the timing of the development of the Arden Precinct and the levels of demand added by the development.

3.3.2 J Zone Substation Rebuild

DESCRIPTION	EXPENDITURE	TRIGGER
Rebuild of Spencer Street (J) Zone Substation	$54 million	1. CitiPower's forecast of load growth in the area supplied by the JA Zone Substation increases relative to the forecast of load growth set out in CitiPower's 2026-31 regulatory proposal; and 2. The increase in forecast load growth will result in CitiPower not being able to maintain a N-1 Secure Rating in respect of the JA Zone Substation in circumstances where two new jumbo feeders from the Montague Steet (MG) Zone Substation to Docklands South are constructed, without also implementing the J Zone Substation Project in the 2026–31 regulatory control period. For the purposes of this trigger: 'JA Zone Substation' means the Little Bourke Street Zone Substation. 'N-1 Secure Rating' has the definition given to it in paragraph 3, page 1 of the ESC's 'Final Decision – CBD Security of Supply', dated February 2008. 'J Zone Substation' means the Spencer Street Zone Substation. 'J Zone Substation Project' means the rebuild of the J Zone Substation, at either the current Spencer Street site or any new site that CitiPower considers appropriate. 'MG Zone Substation' means the Montague Street Zone Substation.

Under clause 19.5 of the EDCoP, we have an obligation to take steps to strengthen the security of supply in the Melbourne CBD. The EDCoP requires that, within 30 days of a notice from the ESC, we must provide a plan that outlines security of supply objectives, the date by which the objectives must be met, and specifies the capital and other works to achieve the objectives that meet the RIT-D. If the ESC approves the plan, we must, among other things, ensure that the Melbourne CBD distribution system meets the security of supply objectives specified in the security of supply upgrade plan.[45]

In 2008, we nominated a "N-1 Secure" supply security standard, which means:

> *"The network can maintain the electricity supply after loss of two 66kV sub-transmission line elements with an allowance of 30-minute switching time after the loss of the first element."*

The Docklands or Southwest of the Central Business District supply area is mainly served by the Little Bourke Street zone substation (JA Zone Substation). The JA Zone Substation is served by four 66kV lines, two from the West Melbourne Terminal Station and one from each of the VM Zone Substation and Waratah Place Zone Substation.

The N-1 Secure rating of the JA Zone Substation is the cyclic rating of the remaining transformer when two transformers fail, which is 63.9MVA in the summer and 63.7MVA in the winter, and the operational load transfer capability of the network, which is 40.1 MVA.

The Docklands area has been identified as a region of high load growth with numerous applications already received for large load connections, such as the Crown Plaza, Melbourne Quarter and North Wharf. Our forecasts show that, as a result of the projected high load growth in the Docklands area, the JA Zone Substation will not be compliant with its N-1 Secure rating by 2027.

We have considered several options to meet the forecast demand and compliance requirements in the area served by the JA Zone Substation. Our preferred option is to construct two new jumbo feeders from the Montague Steet (MG) Zone Substation to Docklands South, and rebuild the decommissioned Spencer Street (J) Zone Substation. Further details are provided in the associated business case[46].

We are proposing that the rebuild of the J Zone Substation be included in our 2026–31 determination as a contingent project. We are proposing this as a contingent project as there is some uncertainty as to whether the rebuild will need to be undertaken in the 2026-31 regulatory control period, due to uncertainty over the profile and timing of expected load growth in the area served by the J Zone Substation. In the first instance, we will construct two new jumbo feeders to maintain a N-1 Secure rating from 2027 (being the time at which we first expect to drop below this rating, based on current forecasts of load growth). However, we expect that the J Zone Substation rebuild will also be required, at some stage in the near future, as our load growth forecasts demonstrate that the JA Zone Substation is likely to breach its N-1 Secure Rating by 2031, even with the two new jumbo feeders. As the precise profile and timing of load growth is uncertain, the required timing of the rebuild cannot be predicted with certainty.

The J Zone Substation Rebuild contingent project meets the NER requirements

In respect of the requirement in clause 6.6A.1(b)(1) of the NER, that the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives, we consider that the J Zone Substation Rebuild contingent project will be required for us to comply with a regulatory obligation associated with the provision of direct control services. 'Regulatory obligation' is defined, for the purposes of the NEL and the NER, in section 2D of the NEL, and includes, at (1)(a)(ii), a 'distribution reliability standard' and at (1)(b)(v):

45 EDCoP, clause 19.5.5(b).
46 CP BUS 3.04 – CBD security of supply – Jan2025 – Public.

"an obligation or requirement under an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act (other than national electricity legislation or an Act of a participating jurisdiction or an Act or instrument referred to in subparagraphs (ii) to (iv)), that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination or transmission determination."

Clause 19.5.5(b) of the EDCOP falls within the definition of regulatory obligation or requirement as set out in both of subparagraphs 2D(1)(a)(ii) and (1)(b)(v) of the NEL. 'Distribution reliability standard' is defined in the NEL as "a standard imposed by or under the NER or jurisdictional electricity legislation relating to the reliability or performance of the distribution system." The EDCOP is a standard imposed by the ESC, under section 47 of the Electricity Services Commission Act 2001 (Vic) (**ESC Act**), and clause 19.5.5(b) relates to the reliability or performance of the distribution system.

In terms of the definition in 2D(1)(b)(v), the EDCoP is an instrument, made under section 47 of the ESC Act, that materially affects the provision by us of electricity network services that are the subject of our distribution determination. Clause 19.5.5(b) of the EDCoP is therefore a 'regulatory obligation' for the purposes of the NEL and NER, and the J Zone Substation Rebuild contingent project is reasonably required for us to comply with this regulatory obligation associated with the provision of direct control services.

The J Zone Substation Rebuild also meets the criteria set out in clause 6.6A.1(b)(2) of the NER, as the proposed contingent capital expenditure:

- is not otherwise provided for in the total of the forecast capital expenditure for the 2026–31 regulatory period;
- reasonably reflects the capital expenditure criteria in clause 6.5.7(c), taking into account the capital expenditure factors in clause 6.5.7(e);
- exceeds $30 million or five percent of the value of our proposed annual revenue requirement for the first year of the relevant regulatory period, whichever is greater;
- there are no relevant regulatory information instrument requirements, other than a requirement that we list our proposed contingent projects in our reset regulatory information notice.

The trigger is appropriate, in accordance with clause 6.6A.1(c), as:

- it is reasonably specific and capable of objective verification. Whether or not we can maintain a N-1 Secure Rating at the JA Zone Substation will depend on whether that Zone Substation is operating above the parameters of the N-1 Secure Rating for that Zone Substation. This is easily verifiable;
- it is an event, which, if it occurs (i.e. we receive a connection application or applications which make it apparent that it cannot maintain a N-1 Secure Rating at the JA Zone Substation) makes the undertaking of the contingent project reasonably necessary in order to achieve the relevant capex objectives, in this instance being:
  - to meet or manage demand for standard control services; and
  - to maintain the quality, reliability and security of supply;
- the event will generate costs that relate to a specific location, being the Docklands area of Melbourne, rather than the distribution network as a whole;
- it is described in such a way that the occurrence of the event is all that is required for the distribution determination to be amended under clause 6.6A.2; and

- the occurrence of the event is probable during the 2026–31 regulatory period, but the inclusion of capital expenditure in relation to the event under clause 6.5.7 is not appropriate because the precise timing of the event will depend on whether the connection applications that are the basis of our forecast demand progress to connection, and whether therefore load growth is consistent with our forecast.

3.3.3 R Zone Substation Rebuild

DESCRIPTION	EXPENDITURE	TRIGGER
Rebuild of R Zone Substation	$68 million	CitiPower: 1. prepares a business case and relevant regulatory investment test for distribution documentation, including a cost-benefit analysis that demonstrates that the Preferred Option is rebuilding the R Zone Substation; and 2. obtains all relevant internal approvals to proceed with the project. For the purposes of this trigger: 'Regulatory investment test for distribution' has the meaning given to that term in the NER. 'Preferred Option' has the meaning given to that term in the NER.

Richmond (R) Zone Substation is served by three sub transmission lines from the Richmond Terminal Station. It supplies customers in the Richmond, Cremorne, South Yarra and Toorak areas. Our forecasts show that demand is expected to increase in these areas in the 2026–31 regulatory period, driven by population growth and Victorian Government housing policies, including plans to replace single dwelling homes and existing social housing with large apartment towers.[47] These areas, in particular, are seeing continued household densification, with single dwelling homes and shops being replaced by residential apartment towers around major transport and entertainment precincts.

Maximum demand at the R Zone Substation currently exceeds its summer and winter N-1 thermal capacity ratings of 30.1 MVA and 49.9 MVA respectively. Our forecasts indicate that the R Zone Substation will remain above these ratings in the 2026–31 regulatory period.

The preferred option for managing this issue in the 2026–31 regulatory period is to transfer load from the R Zone Substation to adjacent substations, being the Toorak (TK), Balaclava (BC) and North Richmond (NR) Zone Substations.

However, our preferred option is only appropriate if demand for the 2026–31 regulatory period does not exceed our current forecast of that demand. If demand is above our current forecast, we will need to introduce an additional measure to meet this demand. The most appropriate option is likely to be a rebuild of the R Zone Substation to allow for greater load capacity in its service area.

[47] See, for example, We Need More Homes Close To Train Stations And Trams | Premier; Biggest Urban Renewal Project Delivering Even More Homes | Premier; 240920-Biggest-Urban-Renewal-Project-Delivering-Even-More-Homes-.pdf and Essex Street, Prahran and Simmons Street, South Yarra housing | Engage Victoria.

The R Zone Substation Rebuild is an appropriate contingent project as the need for the project in the 2026–31 regulatory period is uncertain and will depend on whether demand levels in the period are in line with, or exceed, our current forecasts.

The R Zone Substation Rebuild contingent project meets the NER requirements

In respect of the requirement in clause 6.6A.1(b)(1) of the NER, that the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives, we consider that the R Zone Substation Rebuild contingent project will be required to meet or manage the expected demand for standard control services, and to maintain the quality, reliability or security of supply of the distribution system and standard control services.[48]

As explained above, our preferred option to manage forecast demand in the area supplied by the R Zone Substation in the 2026–31 regulatory period is dependent on there being no material increase in demand in that period above our current forecast levels. If demand is above our current forecast, which is very possible due to the Victorian Government's plans to materially increase housing density in the areas served by the R Zone Substation, we will need to undertake further work to manage the demand for standard control services. We consider the rebuild of the R Zone Substation is the most appropriate work to meet or manage this demand, and maintain the quality, reliability and security of supply of standard control services.

The R Zone Substation Rebuild also meets the criteria set out in clause 6.6A.1(b)(2) of the NER, as the proposed contingent capital expenditure:

- is not otherwise provided for in the total of the forecast capital expenditure for the 2026–31 regulatory period;
- reasonably reflects the capital expenditure criteria in clause 6.5.7(c), taking into account the capital expenditure factors in clause 6.5.7(e);
- exceeds $30 million or five percent of the value of our proposed annual revenue requirement for the first year of the relevant regulatory period, whichever is greater;
- there are no relevant regulatory information instrument requirements, other than the requirement that we include our contingent projects in our reset regulatory information notice.

The trigger is appropriate, in accordance with clause 6.6A.1(c), as:

- it is reasonably specific and capable of objective verification. Cost-benefit analysis is commonly used by network service providers and is accepted as an appropriate tool for assessing whether a network augmentation should proceed. Their objectivity is one of the reasons they are used so commonly by network service providers – the outcome is entirely dependent on numbers;
- it is an event, which, if it occurs makes the undertaking of the contingent project reasonably necessary in order to achieve the relevant capex objectives, in this instance being:
    - to meet or manage demand for standard control services; and
    - to maintain the quality, reliability and security of supply;
- the event will generate costs that relate to a specific location, being the Richmond, Cremorne, South Yarra and Toorak areas of Melbourne, rather than the distribution network as a whole;
- it is described in such that the occurrence of the event is all that is required for the distribution determination to be amended under clause 6.6A.2; and
- the occurrence of the event is probable during the 2026–31 regulatory period, but the inclusion of capital expenditure for which on a forecast basis is not appropriate, given the inherent uncertainty

[48] NER, clause 6.5.7(a)(1) and (3).

of demand forecasting, particularly in the face of the Victorian Government's plans for greater housing density in the relevant areas, with the result that the precise timing of the event is not certain.

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