



Transformer replacements

UE RRP BUS 4.03 – Transformer
replacement – Dec 2020 – Public

Revised regulatory proposal 2021–2026

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1 Overview

Our original proposal outlined the zone substation transformer replacements we will undertake over the 2021–2026 regulatory period. This forecast reflected the risk monetisation modelling we use to identify the least-cost solution to managing zone substation risk, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures. This approach is consistent with our internal practices, and the AER's recent asset replacement practice note.

Our monetisation approach received support from many stakeholders, including Energy Consumers Australia. The draft determination supported the use of our monetisation modelling, but raised concerns over some of the input assumptions relied upon.

This business case addendum sets out our response to the draft determination, including the changes we have made to revise and further test the concerns raised. In support, we have provided the following additional information:

- updated transformer risk model found at UE RRP MOD 4.04 - Transformer risk - Dec2020 - Public
- updated Kaplan-Meier analysis found at UE RRP MOD 4.08 - Kaplan-Meier model - Nov2020 - Public

This addendum should also be read in conjunction with the following documents provided as part of our original proposal, or in response to information requests from the AER:

- UE BUS 4.03 – zone substation transformer replacements: forecast method overview
- UE IR007 – zone substation transformer and switchgear replacement business cases
- UE ATT139 – asset risk quantification guide.

Consistent with the reasons provided in this addendum, our revised proposal forecast for transformer replacements is set out in table 1.1.

Table 1.1 Capital expenditure forecasts: zone substation transformers (\$ million, 2019)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Original proposal	5.6	6.1	7.0	7.3	6.7	32.7
Draft determination	3.9	3.0	3.0	3.0	3.3	16.4
Revised proposal	4.9	5.5	5.5	4.0	1.6	21.6

Source: United Energy

2 Background

2.1 Our original proposal

For the reasons outlined in our original proposal and UE BUS 4.03, we proposed to increase the volume of transformer replacements over the 2021–2026 regulatory period. These reasons include:

- the risk of failure is increasing, based on our network experience, as our transformer population continues to deteriorate over time—without intervention, by 2025 there will be 23 transformers in our network that are older than 60-years
- we are the second most utilised network in Australia, meaning we face higher consequences of failure relative to other networks
- we do not manage assets so they never fail, but rather, we invest to manage the consequences of failure
 - we consider and implement non-replacement solutions to reduce risk
 - we utilise relocatable transformers to reduce the consequence of failure (for our network, these are more efficient than a spare and have faster mobilisation)
 - as at December 2019, our relocatable fleet includes two mobile 66/22kV power transformers, and one mobile 66/11kV transformer
- notwithstanding an increase in transformer replacements in the 2021–2026 regulatory period, the number of zone substations where we are managing risk is commensurate with the 2016–2020 regulatory period
 - over the 2016–2020 regulatory period, we are managing risk at 15 sites through a mix of asset replacement and works to prepare for relocatable transformers
 - in the forecast period, we proposed to manage risk at 19 sites.

2.2 Draft determination

The draft determination did not accept our proposed capital expenditure forecast for zone substation transformers. The reasons cited included the following:

- demand forecasts may be overstated, and the value of customer reliability (VCR) should be updated
- unserved energy may be overstated due to our weighting of the 10th and 50th percentile probability of exceedance of peak demand and the expected value of unserved energy should take account of the load duration curve as it is not a function of the peak demand alone
- the probability of major failure is three-fold higher than for minor failure (possibly due to causes of asset transformer retirements, as opposed to all failures including repairable failures), and this is overstating probabilities of failure
- evidence of actual failure consequence costs was not provided (including the impact of mobile transformers)
- deliverability concerns due to the scale of our proposed transformer program
- doubt over the extent to which we rely on this risk monetisation modelling for internal purposes.

In light of these concerns, the AER substituted our forecast for the 2021–2026 regulatory period with our historical expenditure for the 2016–2019 period (scaled to provide a five-year forecast).

3 Revised proposal

Our revised proposal forecasts a reduced volume (and therefore expenditure) for zone substation transformers than included in our original proposal. The reduction in our revised proposal is driven by updating demand forecasts, the application of the AER's recent changes to the VCR (which were not available at the time our original proposal was prepared), and further testing of the probability and consequence of failure (consistent with the draft determination).

A summary of the changes to our forecast is provided in table 3.1.

Table 3.1 Revised timing of forecast zone substation transformer replacements (commissioning year)

Zone substation	Original proposal	Revised proposal
Ormond (OR)	2021	2021
Elsternwick (EL)	2021	2021
East Malvern (EM)	2022	2022
Elwood (EW)	2022	2022
Gardiner (K)	2023	2023
Sandringham (SR)	2023	2023
Surrey Hills (SH) re-development	2023	2023
Bentleigh (BT)	2024	2024
Hastings (HGS)	2024	2024
West Doncaster (WD)	2024	Deferred
Oakleigh East (OE)	2025	2025
Bulleen (BU)	2025	2025
Glen Waverley (GW)	2025	Deferred
Beaumaris (BR)	2026	Deferred
Mordialloc (MC)	2026	Deferred
Carrum (CRM)	2026	Deferred
Springvale South (SS)	2027	Deferred

Source: United Energy

Note: Some costs for our OR, EL, EM and EW zone substations will be incurred in the 2016–2020 regulatory period. Only the proportion of costs incurred within the forecast period are proposed.

Our revised forecast, however, is higher than the draft determination. This reflects the reasons outlined previously in section 2.1—notably, historical expenditure is insufficient to manage the increasing risk at these sites. Further, we do not accept the draft determination with respect to the weighting of probability of exceedance, deliverability risk, or the use of our monetisation modelling for internal purposes.

We discuss these concerns in below.

3.1 Response to AER draft determination

We have taken on much of the AER and EMCa's feedback on board, and have revised our monetisation modelling accordingly which is attached to this addendum.¹ The AER criticised several inputs to our risk quantification models, which we have updated. These all affect the forecast in different ways, with some input changes deferring and some bringing replacement forward, sometimes having multiple influences on the same substation.

Overall, the application of updated figures to correlate with the AER's concerns has had the effect of driving down the forecast from the original proposal.

3.1.1 Updated demand forecast and the application of zone substation specific VCR

The AER considered our demand forecasts were overstated, and that the VCRs did not reflect the most recent values.

We accept the AER's position and have updated these parameters. The updated demand forecast takes account of the impact of COVID-19, however, as they were produced before the Federal Government's budget stimulus package was announced, they do not include this impact and we therefore consider them to be conservative. We note these are the same forecasts we use for internal network planning.

We have also applied zone substation specific VCR's in accordance with the AER's 2019 VCR decision. Due to the timing of the AER's VCR decision, we had not been able to incorporate these into our original proposal.

These changes have deferred the timing of some transformer replacements, which has been reflected in this revised proposal and updated risk model.

3.1.2 Weighting of probability of exceedance and load duration curves

For the unserved energy calculation, we apply a 30 per cent weighting to the 10th percentile demand forecast and a 70 per cent weighting to the 50th percentile demand forecast. The AER considered this may overstate unserved energy, and stated:

'EMCa noted that the use of this demand treatment in the context of assessing asset replacement timing may not be appropriate:

"We consider the key issue here is the application of a planning methodology to estimate the expected value of unserved energy. We consider that United Energy is incorrect in stating that the 50% PoE does not represent a realistic expectation of demand. However, the expected value of unserved energy is not a function of the peak demand alone. It should take account of the Load Duration Curve, since the amount of energy unserved (if any) as a result of an equipment outage depends on the load during the time of the outage, and this also is influenced by any mitigation measures...United Energy has not demonstrated that its 70:30 assumption is valid for DNSP planning purposes."

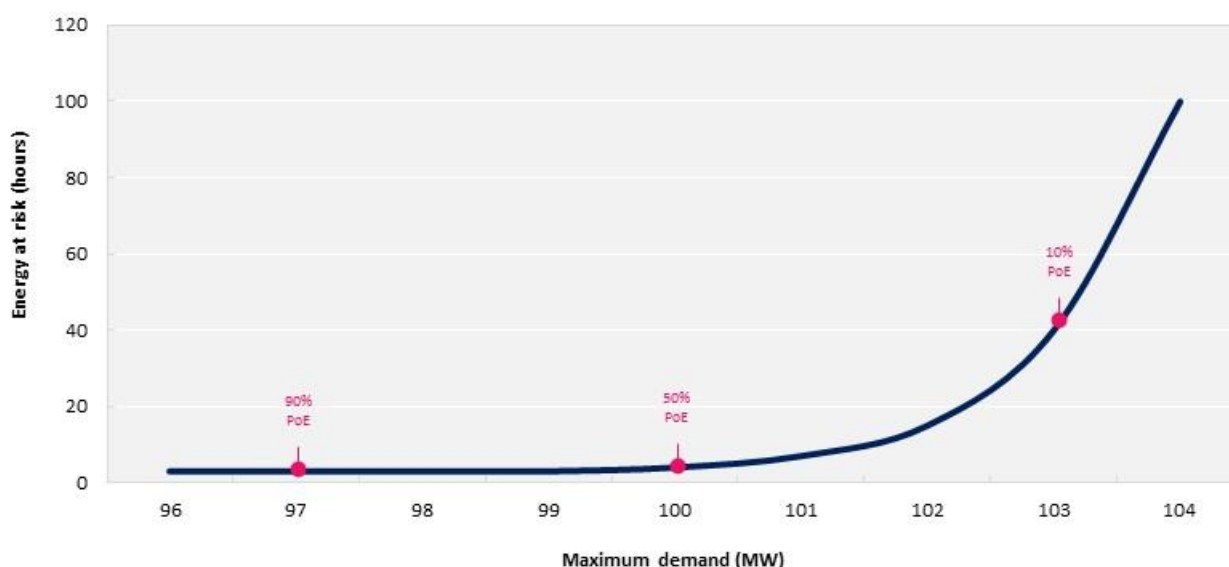
If we were to adopt the 50th percentile probability of exceedance (PoE) demand forecast, all the proposed transformers in this revised proposal are still economic to replace in the 2021–2026 regulatory period. That is, using just the 50th percentile PoE demand forecast does not defer any replacements beyond the next period.

¹ UE RRP MOD 4.04

Notwithstanding this, we do not accept the AER and EMCa's position, and make the following observations:

- through the draft determination and subsequent discussions, it appears the AER and EMCa believe we assume all failures occur at peak times (i.e. that we have not used a load duration curve to estimate our energy at risk). This is factually incorrect. Our risk modelling considers energy at risk, which is a function of both peak demand and the load curve. Specifically, our risk models look at the daily load profile over a whole year, which varies between summer and winter months, as well as having different shapes in both the 10th percentile PoE demand and 50th percentile PoE demand years. This approach is used for both planning and asset replacement purposes
- EMCa's recommendation to the AER is premised on the 50th percentile PoE being a realistic expectation of demand. We do not disagree, however it is not a realistic expectation of *unserved energy* (see next point). This is the parameter that drives the replacement outcomes and hence needs to be 'realistic'
- we have demonstrated that mathematically, a 100 per cent weighting on the 50th percentile PoE (as suggested by the AER) is not representative of expected unserved energy. The relationship between maximum demand and energy at risk is not linear and so using 100 per cent on the 50th percentile PoE demand significantly understates expected unserved energy and hence is not realistic—as illustrated in figure 3.1, although the 50th percentile PoE may represent the mean, the expected value of energy at risk will lie between the 50th percentile and 10th percentile PoE values

Figure 3.1 Illustrative example of relationship between maximum demand and energy at risk



Source: United Energy

- a 30:70 split is a reasonable basis for assessing a weighted average energy at risk figure over a range of forecast scenarios due to the non-linearity in the energy at risk (area under the load curve), and is no different to forming a weighted average risk figure for other asset risks where there is a range of possible consequences. For example, a fire start may have no impact, a minor impact, or a major impact which is likely

to be orders of magnitude large than a minor impact. It is necessary to derive a weighted average cost, not just assume the middle consequence is an average of the three

- our weightings are the same as those applied by Australian Energy Market Operator (AEMO) in Victoria²
- our approach has been consistently applied by our network for 20 years:
 - over all previous regulatory periods the AER has approved forecasts based on this planning approach. If the AER considers this standard to be inappropriate, it should have included this in its 2019 replacement expenditure planning note and provided us, and all distributors, fair process under the National Electricity Rules' consultation procedures
 - irrespective of the 'right' PoE forecast to use, any *change* in PoE forecast changes network reliability, particularly when the change is in respect to a major asset class such as zone substation transformers. If the AER seeks to fund us for lower levels of reliability, it must provide a corresponding adjustment to the service target performance incentive scheme for the expected financial penalties that will arise
- EMCa outlined

'United Energy has asserted that the 70:30 method is the method used by all Victorian DNSPs. We are not able to verify this, however we have not encountered a 70:30 weighting being applied in planning methods in other DNSPs across the NEM or in Western Australia.'

Rather than not being able to verify this, it would appear EMCa made no attempt to verify this as both Jemena and AusNet have informed us that they adopt the same approach. This is also evident, for example, in Jemena's Distribution Annual Planning Report (DAPR) and AusNet's Asset Risk Assessment Overview and its Planning Report Maffra (MFA) Zone Substation replacement expenditure business case submitted as part of their regulatory proposals.³

Thus, the AER's decision enshrines different reliability standards in different Victorian networks. That is, our customers can now expect to experience worse supply reliability than in other network areas all things being equal. The AER has not outlined any basis for this being appropriate

Similarly, EMCa noted it had not encountered our approach before and used this to imply our approach overstates expected unserved energy. We are aware that EMCa conducted a similar review of SA Power Network's (SAPN) regulatory proposal. According to SAPN's DAPR, it plans its network to accommodate the 10% PoE demand under system normal conditions, and 50% PoE demand under N-1 conditions.⁴ This is a considerably higher standard than our 70/30 weighting approach.

We also sought information from Western Power, the Western Australian distributor and transmission business. They advised that in distribution, they are governed by deterministic planning and rarely, if ever, undertake unserved energy economic style analysis. In their transmission planning, they do undertake economic cost benefit analysis and rely 100 per cent on the 10 percent cent PoE forecasts. Again, these are much higher standards than our approach.

We reject EMCa's assertion that we are overstating energy at risk in relation to other networks.

² AEMO, *Victorian Annual Planning Report*, June 2019, p. 87.

³ Jemena, *Jemena Electricity Networks (Vic) Ltd 2019 Distribution Annual Planning Report*, 31 December 2019, p. 40. AusNet, *Asset Risk Assessment Overview*, 3 October 2019, p. 18. AusNet, *Planning Report Maffra (MFA) Zone Substation*, 22 July 2019, p. 12.

⁴ SAPN, *Distribution Annual Planning Report 2019/20 to 2023/24*, p. 38, 39.

- the AER, citing EMCa, stated our calculation of unserved energy 'may' be overstated and the use of this demand treatment in the context of assessing asset replacement timing 'may' not be appropriate. The AER has not provided evidence that our approach is incorrect, or evidence that 100 per cent weighting on the 50th percentile PoE is better. Should the AER's reasoning have been proposed by a distributor, it would not have been accepted.

3.1.3 Updated probabilities of minor and major failures

In our original proposal, we used a Kaplan-Meier (K-M) analysis to approximate the probability of a catastrophic failure. We then used a mixture of University of Queensland failure surveys and historic experience to approximate major and minor failure ratios. The AER questioned whether the University of Queensland failure survey only consider catastrophic failures causes rather than all failures.

We accept the AER's concern and have now updated our K-M model by considering historical fault data only.⁵ We have correspondingly updated our risk model inputs to align with recorded actual consequences (also refer to section 3.1.4 below, where we consider consequence costs) as attached to this addendum.⁶ By using all our failure data (i.e. both repairable failures and catastrophic failures), these updates have lowered the probability of a catastrophic failure and increased the probability of failure of a repairable failure. The results are outlined below.

Table 3.2 Updated failure probabilities

	Weibull scale parameter	Weibull shape parameter	Repairable (%)	Catastrophic (%)
Original proposal	105	3.6	27	73
Revised proposal	85	3.6	80	20

Source: United Energy

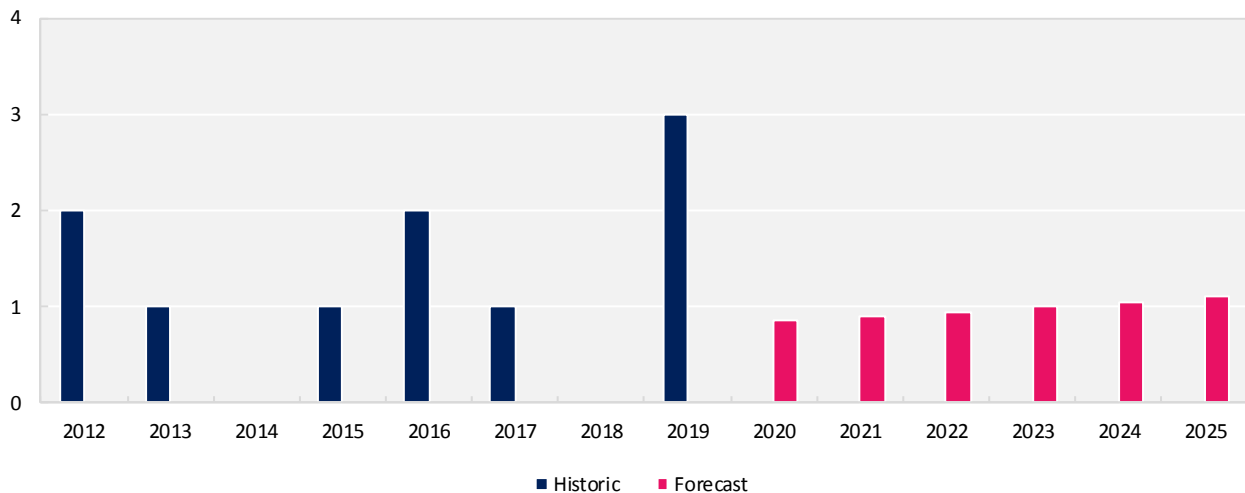
We have validated the revised model output which shows the reliability curve results in a forecast fleet fault rate that correlates well with historic faults. Over the six-year period from 2014–2019 we experienced seven faults, and over a six-year forecast from 2020–2025 we predict around six faults. This is shown in figure 3.2.⁷

⁵ UE RRP MOD 4.08. Faults with an outage duration of less than 7 days were excluded to align with CIGRE's transformer failure surveys. CIGRE, *Power transformers and reactors*, 2015, TB 642.

⁶ UE RRP MOD 4.04

⁷ Updated from faults presented in UE BUS 4.03 to only include faults over 7 days and for minor timing discrepancy.

Figure 3.2 Actual and forecast transformer faults



Source: United Energy

3.1.4 Actual fault consequence costs

The AER considered we should use actual consequence of failure costs where possible.

In our regulatory proposal we assumed a repairable fault cost of \$200,000 (\$2019). We accept the AER's concern and have now used the actual cost of a repairable failures of \$136,045 (\$2019) to derive the revised probability of failure curves and consequence ratios outlined in 3.1.3. This figure is the average of all recorded fault costs.

We have also revised the outage durations based on actual outage durations from faults; a catastrophic failure was revised downward from 180 to 152 days and a repairable failure was revised upward from 24 days to 25 days.

3.1.5 Deliverability plan

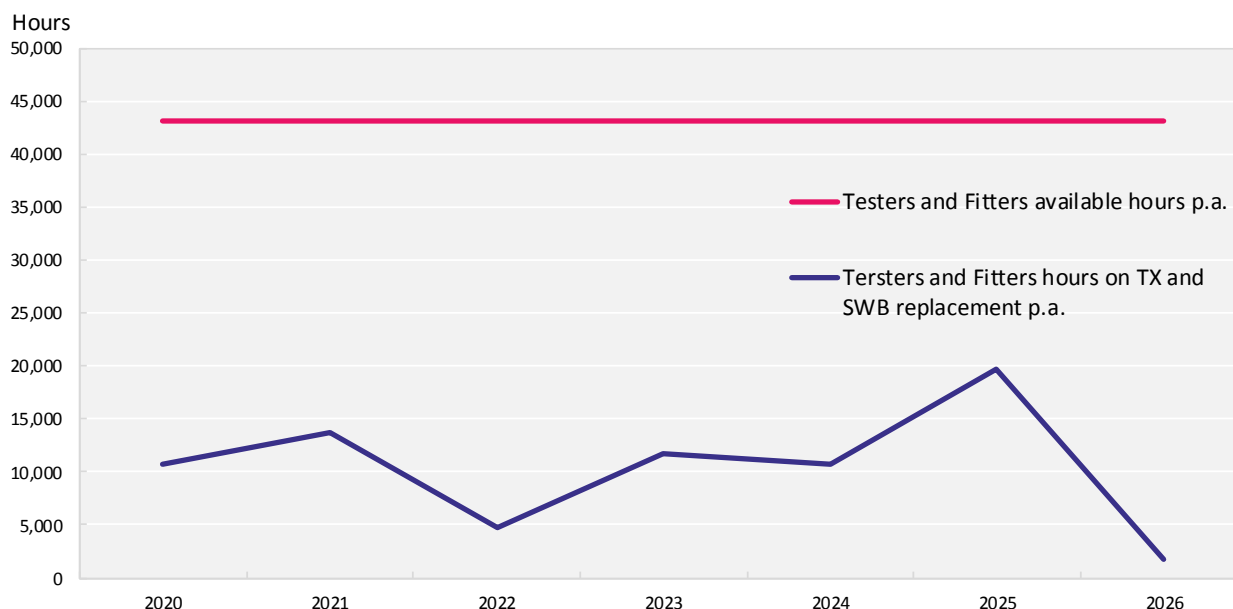
This transformer program sits well within our delivery capability.

The greatest number of transformers we are proposing to commission in a year is three, in 2023. This is not a particularly large number of transformers—in 2017/18, we also commissioned three transformers.

We have an outsourced model where transformer works can be awarded to any resource partner on our panel. Typically, we use around eight testers and 16 fitters per year. This represents only a portion of the fitters and testers available to us through our resource partners.

Even within the typical workforce we use, this transformer program can be readily fitted within our works program. Figure 3.3 shows the workload of our transformer and switchgear programs combined—these represent the major work programs for typical fitters and testers workforce over the 2021–2026 regulatory period. It shows these major programs represent a modest workload for our typical workforce.

Figure 3.3 Testers and fitters available hours compared to transformer and switchgear program hours



Source: United Energy

Further, over the current regulatory period our testers and fitters have been installing rapid earth fault current limiters (REFCLs) at Dromana, Mornington and works and the Frankston South REFCL. This was a major works program that has now finished meaning the transformer works can be delivered with this workforce (again noting there are more fitters and testers available to us through our resource partners if needed).

3.1.6 Transition to risk-based asset management

Our forecast replacement expenditure for transformers have been developed using the risk monetisation modelling provided to the AER (and EMCa) in our original and now revised proposal. This same approach and model, which is based on overall zone substation risk, is used for internal asset management planning.

We understand our risk model approach is the most sophisticated approach being used in the National Electricity Market. We assess total station risk meaning we take a holistic view of risk rather than looking at asset risk individually.

The reason we did not complete all the transformer replacements that were economic to replace using this model over the current regulatory period, is because this model was not available for the full regulatory period. It has been recently developed and is now being applied by our business. This includes undertaking replacements where the optimal timing is in the past, and future replacements as they come due and are scheduled within our overall works program.

For example, we are currently undertaking replacements at Cheltenham and Elsternwick as they are economic under our new risk model. Using this risk model, we also deferred investment in transformers replacements at Doncaster and Mordialloc over 2016–2020 as highlighted in our original proposal.⁸ We use the same risk model

⁸ UE APP02.

to develop our forecasts outlined in our original proposal and this revised proposal, as we as we do in practice, and it is incorrect to suggest otherwise.

3.2 Revised proposal forecasts

Consistent with the reasons provided in this addendum, our revised proposal forecast for transformer replacements is set out in table 3.3.

Table 3.3 Capital expenditure forecasts: zone substation transformers (\$ million, 2019)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Revised proposal	4.9	5.5	5.5	4.0	1.6	21.6

Source: United Energy