Transformer replacement

RRP BUS 4.03

Revised proposal 2021–2026

CitiPower

December 2020

Contents

1 Overview

In our original proposal, we forecast the replacement of five zone substation transformers—two each at our North Richmond and Celestial Avenue zone substations, and one at our Victoria Market zone substation. These replacements were justified using risk monetisation modelling, having regard to the probability of failure, and the likelihood and potential consequences of failure in terms of safety, environmental, financial, and supply reliability.

This business case addendum sets out our response to the draft determination and describes the further work we have undertaken since our original proposal. This includes the development of scoping documentation and associated costings for each zone substation. This addendum should be read in conjunction with the following documents:

- the attached transformer functional scopes, outlining the required replacement works and costs (CP RRP ATT46, CP RRP ATT47, CP RRP ATT48).
- City of Melbourne service request document demonstrating restrictions on work practices (CP RRP ATT49)
- original business case (CP BUS 4.03)
- original risk-monetisation models (CP MOD 4.12, CP MOD 4.13 CP MOD 4.14, CP MOD 4.15, CP MOD 4.16)

For the reasons provided in this addendum, our revised forecast for zone substation transformer replacements is presented in table 1.1.

Table 1.1 Capital expenditure forecasts: zone substation transformer replacements ($ million, 2019)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Original proposal	2.7	5.6	5.2	3.3	1.5	18.3
Draft determination	1.1	2.3	2.2	1.4	0.6	7.6
Revised proposal	3.8	5.0	4.2	2.6	0.9	16.4

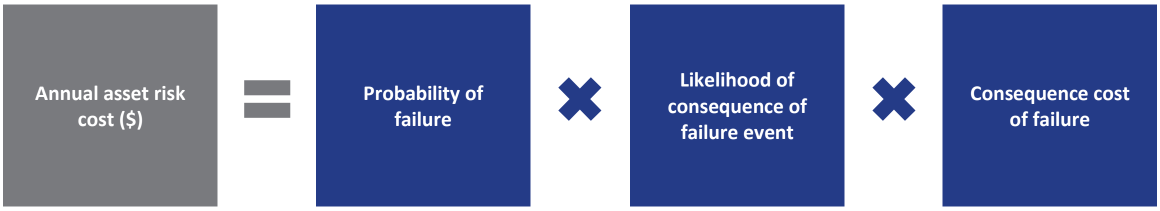
Source: CitiPower

2 Background

2.1 Our original proposal

In our original proposal we explained our risk monetisation process and how it was used to determine our zone substation transformer replacement program. We monetise risk when assessing investment decisions by determining the annual asset risk cost (as shown in figure 1.1). This approach is applied to all identified failure modes for an asset, and the sum of the annual asset risk cost for all of failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.

Figure 2.1 Calculation of annual asset-risk cost



Source: CitiPower

Our approach to risk monetisation used the probability of failure from our condition based risk management (CBRM) model, and cost of consequence and likelihood of consequence modelling to provide a robust approach for the preparation and application of the required input information.[1] Our CBRM model enabled us to use current asset information, engineering knowledge and practical experience to predict future asset condition and performance.[2] Our risk monetisation modelling is a comprehensive approach, which is aligned with the AER's risk monetisation process.

Our original proposal included the replacement of five zone substation transformers over the 2021–2026 regulatory period. In the context of asset condition, we considered this forecast to be modest:

- we currently have three zone substation transformers that are at or nearing end-of-life, as demonstrated by our CBRM modelling
- in the absence of intervention, this number will jump to 20 by the end of 2026
- after our forecast interventions (i.e. the replacement of five zone substation transformers), we will still have 10 zone substation transformers that are at, or nearing, end-of-life.

2.2 AER's draft determination

The draft determination notionally included five transformer replacements, but reduced the unit cost for these replacements by 59 per cent compared to our original proposal (i.e. to $1.5 million, $2019). This resulted in a substitute estimate for zone substation transformers of $7.6 million ($2019). The reasons cited by the AER included:

- there was insufficient options analysis—the risk monetisation does not test options, but rather, assumes the five transformers are candidates for replacement and then tests the optimal timing

1 Note the consequence cost of failure modelling was undertaken within our risk monetisation spreadsheets (i.e. CP MOD 4.12 to 4.16).

2 The CBM is a proprietary model developed by EA Technologies. The model is an ageing algorithm that takes into account a range of inputs to produce a health index for each asset in a range from zero to 10 (where zero is a new asset and 10 represents end of life). The health index provides a means of comparing similar assets in terms of their calculated probability of failure.

- the risk cost was overstated because the likelihood of consequence, cost of generation and probability weighted demand forecast are overstated
- as the projects progress, cost efficiencies are likely to be identified. This included considerations that the unit costs appeared higher than other distributors' unit costs, and higher than our forecast unit costs for transformers replaced in our proposed 6.6kV conversion projects
- the Victoria Market transformer has 10 years until it reaches end of life based on CBRM output.

3 Revised proposal

We maintain that each of the zone substation transformer replacements included in our original proposal will be required in the 2021–2026 regulatory period. Notwithstanding this, we accept that further information was required to support our forecast. In our revised proposal we demonstrate the following:

- options other than replacing these transformers are not practicable or efficient. For example, offloading these transformers is not possible because there is insufficient transfer capacity, and the costs and risks associated with refurbishing aged transformers would be substantial (i.e. the transformers would need to be taken offsite, at substantial cost, and post refurbishment, many of the risks associated with the aged transformer will remain)
- we have not overstated risk costs, and rather, have appropriately considered the likelihood of consequence
- our demand forecast probability weightings are consistent with the other Victorian distributor's approaches, the Australian Energy Market Operator's approach and considerably more conservative than the approaches applied in other jurisdictions.

We have also taken on board the AER's comments that the transformer replacement costs may change as project scopes are refined. To that end, we have re-estimated and reduced our unit costs, and have attached the corresponding functional scopes and estimates to this addendum.[3] In this context, we do not accept the AER's substitute unit rates, and note that the benchmarks used by the AER are not appropriate comparators (e.g. they included material costs only, and failed to take account of the characteristics of our network).

Finally, we outline that while the Victoria Market transformer is younger than the other transformers being replaced, due to the high loading and general degradation, our risk based modelling supports its replacement in the 2021–2026 regulatory period as being economic (i.e. it is a lower cost option than not replacing it).

A summary of our revised proposal forecast is shown in table 3.1.

Table 3.1 Capital expenditure forecasts: zone substation transformer replacements ($ million, 2019)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
NR transformer no. 1	0.0	1.0	1.8	0.8	-	3.6
NR transformer no. 2	-	0.0	1.0	1.8	0.8	3.6
VM transformer no. 1	1.1	1.8	0.7	-	-	3.6
WA transformer no. 1	1.9	0.7	-	-	-	2.6
WA transformer no. 2	0.8	1.5	0.7	-	-	3.0

Source: CitiPower

3.1 Response to draft determination

3.1.1 Options analysis

In its draft determination, the AER considered our risk monetisation did not test options, and simply assumed the five transformers were candidates for replacement and then tests the optimal timing. While replacement

[3] CP RRP ATT46, CP RRP ATT47, CP RRP ATT48,

was proposed because it was the only viable alternative, we accept the AER's concern that this was not outlined in our original proposal. We address these concerns below and demonstrate why offloading and refurbishment options have not been proposed.

North Richmond no. 1 and no 2. transformers

For assets of this type, the average time for the onset of critical degradation is typically 60 years; our North Richmond (NR) number one and two transformers are both 61 years. Additionally:

- the on-load tap changers (OLTC) on these transformers are in poor condition and are the main drivers for intervention
- periodic oil filtration is required to remove reoccurring moisture from the windings and oil
- the transformers' main tank also condition requires attention, and previous attempts to address main tank lid oil leaks by welding have been unsuccessful.

Offloading this transformer is not practicable because the 22kV feeder network has insufficient capacity to offload the transformers to the adjacent zone substations. This is shown in table 3.2, and means expansion to the underground feeder network would be required at significantly higher cost (in excess of $10 million) than replacing the transformers. Additionally, this would not be consistent with the long-term plan to develop a fourth transformer at NR, which is undergoing re-development and growth in the supply area.

Table 3.2 Offloading capacity to nearby zone substations (MVA)

Adjacent zone substations	Required offload (single transformer)	Feeder capacity for offload
Richmond and Camberwell	20	3

Source: CitiPower

Refurbishing these transformers is also unlikely to be prudent or economic, noting that complete refurbishment of aged transformers is not commonly undertaken across the industry. For example, much of the works associated with commissioning a new transformer would be incurred when refurbishing them, including:

- as the main driver for replacing these transformers is the poor condition of the OLTCs, refurbishment would require these transformers to be taken offsite for factory retrofitting, and to address the main tank oil leaks. Specifically, refurbishing OLTCs requires physically entering the main tank to access the terminations, meaning the oil must be dropped to below the winding level. Exposing the windings to natural air for the required two to three weeks would further degrade these (already degraded) transformers. Additionally, sealing the flanges on site is a high-risk activity as any air bubbles forming in the transformer winding can cause dielectric failure when high voltage tested prior to commissioning. The only practicable option is to take the transformer to a workshop (such as Wilsons), where the refurbishment would be undertaken in a controlled atmosphere with dehumidifiers and where the skilled workers will have workshop facilities and required workshop equipment. Upon completion of the job the transformer can then go through the vapour phase dry out and be sealed
- the removal of these transformers for retrofitting would require uninstalling the transformers, relocation costs (both to and from the zone substation) and re-commissioning, as well as the actual refurbishment costs
- the existing sound enclosure would need to be dismantled to establish access to remove the transformer, and subsequently re-built
- replacement of aged paper lead cables and electromechanical protection

- costs associated with replacing ancillary mounted components such as bushings, radiators, fans, current transformers (CT) and temperature monitoring
- there is also a possibility that further defects are found during the offsite works, resulting in large component replacement or complete replacement of the transformer.

Critically, after incurring these costs we would still have two 60+ year transformers back in place, which will have a significantly shorter remaining life than a new transformer. NR no. 1 and no. 2 are also the last two English Electric 104 AFG transformers in our network. The original equipment manufacturer is no longer operational and there are no major components in our spare equipment. Therefore, on an ongoing basis, if a major component were to fail we would need to seek bespoke manufacturing of these parts and subsequent type testing (which as detailed in response to AER information requests, will almost certainly be cost prohibitive).

For the above reasons, the only economic option is to replace these transformers.

WA no. 1 and WA no. 2 transformers

Our Celestial Avenue (WA) number one and two transformers are currently 56 years and will exceed 60 years over the 2021–2026 regulatory period. The main drivers for intervention include the following:

- dissolved gas analysis (DGA) and oil quality results of the WA no. 1 transformer indicates a thermal fault in the windings, with temperatures reaching over 700 degree Celsius within the main transformer tank. The transformer has an online DGA monitor installed to monitor the gassing, however, electrical testing has failed to locate the specific source of the fault
- arcing and thermal fault gasses within the OLTC compartment have also been observed during DGA sampling
- the building ventilation system design is inadequate and external access doors must be opened in summer (meaning a transformer failure may present increased safety risk due to reduced physical barriers).

It is possible to offload these transformers to the newly constructed Waratah Place (WP) zone substation, however, it will consume the majority of the remaining capacity of the station. This capacity is needed to accommodate future projected growth and committed load transfers from adjacent stations (Market Place and Russell Place). If an offload from WA to WP did occur, there would then be a need to construct another zone substation in the eastern central business district (CBD) to maintain the security of supply within the CBD (at a cost in excess of $60 million), which makes this option uneconomic.

It is also not prudent to refurbish our WA transformers as once the transformer windings need replacement, the only practicable option is to replace the whole transformer because windings are the main component and cost of the transformer. Further, for the same reasons outlined for our NR transformers, the transformers would need to be refurbished offsite, meaning many of the major cost items associated with commissioning a new transformer would be incurred anyway. And the resulting assets would still be two 60+ year transformers, which will have a significantly shorter remaining life than a new transformer.

The only economical option is therefore to replace these transformers. An ancillary benefit is replacement will allow us to retain spare equipment to service the remaining fleet of 19 Fuller HS tap changers for maintenance and fault response activities. There are currently no Fuller HS components in spare equipment (and the manufacturer is not operating).

VM no. 1 transformer

Our Victoria Market (VM) number one transformer is currently 53 years old and will be approaching 60 years over the 2021–2026 regulatory period. The main driver for the transformer replacement, however, is the OLTC condition and general deterioration due to high operations leading to higher risk of failure.

A review of offloading options for this transformer demonstrates that offloading is not viable. The program underway to decommission the 22kV zone substations connected to the West Melbourne Terminal Station (WMTS) is reducing subtransmission to distribution transformation capacity in the western CBD by 120 MVA by beginning of the 2021–2026 regulatory period. The program relies on having capacity at Victoria Market, specifically for the offload of Spencer Street (J) and Tavistock Place (TP). If a VM transformer is to be offloaded and not replaced, it would be necessary to review the current WMTS decommissioning project and bring forward plans to construct additional 11kV underground feeder transfer capacity and construct a new zone substation in the North Melbourne area in the 2021–2026 regulatory period. This option would require significant additional capital expenditure (in excess of $40 million) hence is not economic.

For the reasons noted previously, refurbishment options would not be economic. This is further compounded by the general deterioration in the transformer due to high operations, which limits the ability to undertake targeted refurbishments. This means the only prudent option is like-for-like transformer replacement.

3.1.2 Risk cost and likelihood of consequences

EMCa considered our forecast risk cost was overstated because the likelihood of consequence, cost of generation and probability weighted demand forecast are overstated. The AER also referred to the conclusions of EMCa, that when corrected for reasonable assumptions, supported the deferral of a proportion of our proposed transformer projects.

We requested the AER provide what it referred to as more 'reasonable' assumptions, as these were not disclosed in the draft determination or EMCa's report. The AER responded that EMCa did not produce specific sensitivity models for each replacement project or risk model; rather EMCa manually altered parameters within our models, individually and together.

Neither the AER nor EMCa provided any basis for why their substitute assumptions, in isolation or in combination, are more reasonable than our forecasts. Similarly, they did not disclose what combination(s) of sensitivities it relied on (or placed greater weight on) to support its decision. In making a final decision, we consider the AER must be transparent and afford us an opportunity to respond to the actual sensitives that leads to its decision should it continue to adopt this approach. It is also clear from the sensitivity models that EMCa only countenanced down-side sensitivities. That is, its sensitivity analysis was asymmetric.

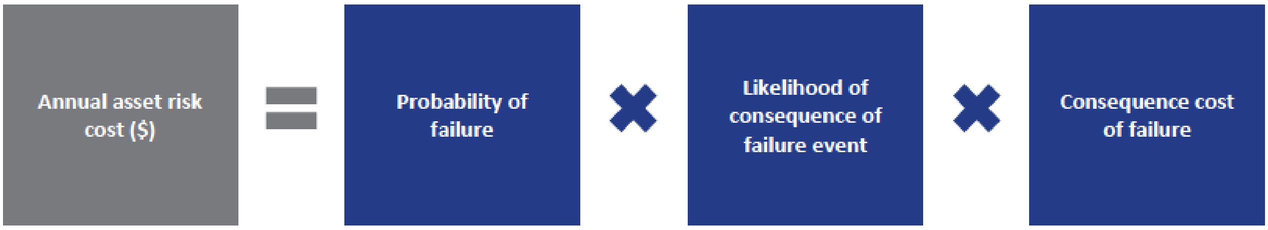
Notwithstanding that we do not know what sensitivities have led to the draft determination, we have sought to comment on the AER's and EMCa's commentary in the following sections.

Likelihood of consequence

In our original business case, we explained that the likelihood of consequence is generally set to 100 per cent on the basis that when a particular failure type occurs, it is known to have a particular consequence. That is, the likelihood of consequence is directly linked to the definition of the failure mode (and naturally the probability of that failure mode occurring)—for example, as the definition of a significant or a major failure is a failure that results in an outage, and the consequences are determined using actual values of load and capacity, then the likelihood of the consequence occurring must be set to 100 per cent. In other words, by definition, these failure modes could not occur without causing loss of the asset and some consequence must occur if there is a significant asset failure.

We understand the risk monetisation model, reproduced in figure 3.1, ordinarily distinguishes between the probability of failure; the likelihood of a failure event; and the consequence cost of a failure. However, it is reasonable to combine the latter two elements in a single variable, providing that the components are estimated appropriately. Or stated alternatively, that these two variables are combined does not necessarily infer that risk costs are overstated, so long as the probability of the failure type is appropriate to the failure type, and not just the probability of a generic 'failure'.

Figure 3.1 Risk monetisation model



Source: CitiPower

In our CBRM, by definition, a major failure will result in irreparable damage to a single transformer, and a catastrophic failure will result in irreparable damage to multiple transformers (in some failures the resulting explosion and fire could result in damage to the adjacent transformer due to the substation layout). That is, the likelihood of consequence values are used to split the major failures into different consequence categories.

The network performance consequence for a catastrophic failure is based on the net load based on the maximum demand, considering the rating and the transfer capacity. While there may be some variation in the exact load depending on the demand at the time of failure, there is a 100 per cent likelihood that the load will be lost due to the defined failure mode.

In setting the consequence of a failure, we have drawn on experience which shows assets are more likely to fail when they are highly loaded as the loading increases the operating temperature and the stresses on the insulation materials. Nevertheless, the financial value of the lost load has been moderated by applying a duration weighting to the value of customer reliability (VCR) for each type of load and this in turn moderates the network performance consequence values. Moderating the load value in addition to this would understate the risk.

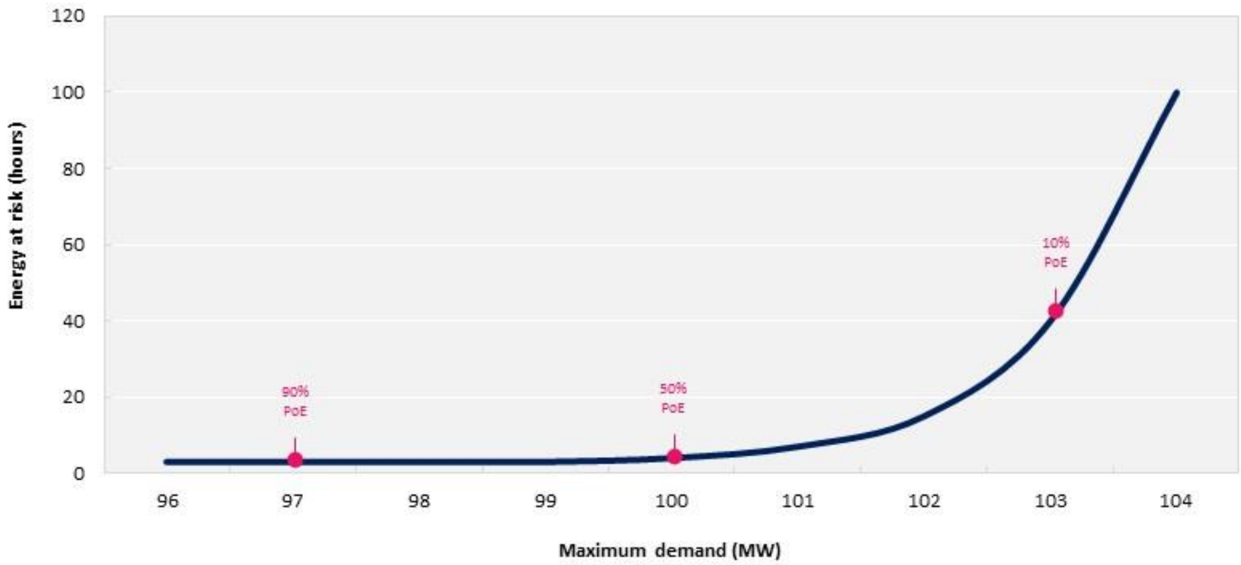
Probability weighted demand forecast

As part of our risk monetisation approach for determining the optimal timing of our proposed transformer replacements, 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 draft determination, however, stated the probability weighted demand forecast are overstated and that no weight should be put on the 10 per cent probability of exceedance (PoE) forecast.

We do not accept this position, and make the following observations:

- 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 3.2, 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 3.2 **Illustrative example of relationship between maximum demand and energy at risk**



Source: CitiPower

- 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 larger 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 Victoria[4]
- 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.

The draft determination also relied on the views of its consultant, EMCa. On this issue, EMCa made the following statement:[5]

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

5 EMCa, *CitiPower – Review of aspects of proposed expenditure*, August 2020, pp. 27–28.

CitiPower 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 reasonable attempt, as both Jemena and AusNet Services have informed us that they adopt the same approach. This is also evident, for example, in Jemena's distribution annual planning report (DAPR), AusNet Services' asset risk assessment overview, and its planning report for the Maffra (MFA) zone substation replacement expenditure business case submitted as part of its regulatory proposal.[6]

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 per cent PoE demand under system normal conditions, and 50 per cent PoE demand under N-1 conditions.[7] 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 such analysis and rely 100 per cent on the 10 percent cent PoE forecasts. Again, these are much higher standards than our approach.

Given the above, we reject EMCa's assertion that we are overstating energy at risk in relation to other networks.

Progressive restoration of supply

EMCa questioned whether our input assumptions adequately reflect the probable extent of the opportunities available to progressively restore supplies in the event of a failure.

The transfer capacity considered in the calculations takes into account the total expected transfer capacity, so no further phased restoration of supply would be possible until generation came online. The transfer capacity values we used were assumed to remain constant over the 2021–2026 regulatory period, but would actually be expected to reduce as the demand increases on the network. Therefore, our costs are likely conservative and not overstated.

Cost of generation

We deploy generation on our network on a weekly basis to support planned works. This ranges in size to support small kiosk substations to large maintenance works of several megawatts. Our costs were developed by our generation team which have significant experience in this area.

EMCa states the estimated costs of generation may be higher than would be incurred during an actual event. Our forecast generation costs are not overstated, and should be considered conservative due to the required scale. For example:

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6 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.

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

- our generation hire contracts are 'ad-hoc' supply contracts. This means our suppliers are not required to have generation reserved for us. The generation hire costs used in our model, however, are based on standard generation costs which assumes the required generators would be readily available. In reality, the number of generators required would not all be available on short notice and would almost certainly require additional generation support from interstate, which significantly increases hire costs
- generation support of this size could be expected to use over 120,000 litres of fuel per day (e.g. in CP MOD 4.12 for NR). This volume of fuel cannot be locally purchased and requires setting up fuel storage, which we have not included in our costs
- the costs assume generators can be located at a number of 5 MW sites. The footprint for a 5 MW generation site would be large and it is unlikely that the required number of sites would be available within the CBD. It is probable that a larger number of smaller sites would be required, which would result in additional associated costs such as transformers, fencing and lighting
- fuel costs assume the generators will respond to actual demand but in practice the generators are set to match expected maximum demand for the duration of their deployment as they cannot be continually varied based on actual demand throughout the day. This means we have understated the fuel costs.

We further note EMCa provided no evidence, or even reasoning, as to why it considered the generation costs may be overstated.

Gross and net risk

EMCa outlined that our risk monetisation assessment compares the total risk cost prior to the replacement occurring with the annualised cost of replacement. It considered this incorrectly assumes that no risk costs will be present when the replacement has been made.

The probability of a newly replaced transformer failing is minimal. Transformers undergo stringent manufacturer testing and further testing in operational conditions once installed by us before they are commissioned. We accept the probability of failure is not zero, however, it is so small that it would have no impact on the optimal replacement timing. For modelling purposes, it is reasonable to assume that the probability of a new transformer failing is zero, and to suggest otherwise indicates an unrealistic and unachievable expectation of modelling precision.

3.1.3 Estimated unit costs

The AER considered that as the replacement projects progress, cost efficiencies are likely to be identified. This included considerations that the unit costs appeared higher than other distributors' unit costs and higher than forecast unit costs for transformers replaced in our proposed 6.6kV conversion projects.

The costs we presented in our original proposal were based on the cost of two recent transformer upgrades in the Powercor network. EMCa considered the following:

> *applying historical costs of similar projects is reasonable at the first approval gate as the accuracy of the cost estimates are likely to be improved as the project is developed, risks are quantified, and scoping assumptions are refined.*

For our revised proposal, we have sought to further refine these costs. We have now developed cost estimates based on the individual scopes of each proposed transformer.

The scope and cost details for each transformer are attached with our revised proposal.[8] Through this process, the costs have reduced but remained in line with our original proposal (which is to be expected given the original costs were based on two actual transformer replacements). Table 3.3 outlines the cost differences between our original and revised proposals.

Table 3.3 Transformer unit rates ($ million, 2019)

Transformer	Original proposal	Revised proposal
NR transformer no. 1	3.7	3.6
NR transformer no. 2	3.7	3.6
VM transformer no. 1	3.7	3.6
WA transformer no. 1	3.7	3.0
WA transformer no. 2	3.7	3.0

Source: CitiPower
Notes: This table outlines the full cost of the transformer replacements but less than this is incurred in the 2021–2026 regulatory period

In making its substitute estimate, the AER relied on unit rates referred to by GHD in the context of the AER's repex model, and comparisons to other distributors. The unit rate used by GHD refers only to the transformer component of zone substation works, based on category regulatory information notice (RIN) data. This rate does not capture the full costs of replacing a transformer, as it excludes costs associated with other RIN categories (e.g. switchgear, protection, cable and civil works that are also required). It was also based on works completed almost 10 years ago, noting that many factors have changed since then (e.g. materials and contracts costs, including traffic management and Council requirements have increased substantially, and our works practices have also changed).

Similarly, the AER referenced what it interpreted as lower costs used in our Brunswick and Port Melbourne supply area business cases. The transformer replacement rates in these supply area business cases represent only the materials cost of a zone substation transformer.

We are not able to definitively comment on the other distributors' transformer costs referenced by the AER as it has not provided us with these costs or a reference to where they can be found. In the interest of procedural fairness, we expect that before using other distributors' costs in making a decision the AER should:

- ensure the costs and scope of works are a like for like comparison
- provide us with an opportunity to review the costs and be afforded an opportunity to comment on them.

We have not seen evidence of this to date and therefore do not consider the AER can rely on those costs in making its decision. Further, in making such comparisons the AER needs to be sure it has considered the factors impacting on the costs across different network types, particularly within the CBD where:

- our zone substations are highly space constrained which increases the design and operational complexity of removing the old and installing the new transformers

8 CP RRP ATT46, CP RRP ATT47, CP RRP ATT48,

- large components of these works must typically be undertaken outside standard business hours in accordance with Council requirements, which materially increases labour costs. In the rare occasions where we are able to close entire streets or lanes to conduct our works, such as when we undertook a cable removal and re-installation at Waratah Place (WP), we are still subject to the City of Melbourne's standard condition that:[9]

  Consultation with all local properties affected by the closure must be undertaken prior to implementation, and ***the access arrangements of all businesses, construction sites and local residents must be accommodated as required. Local access must be maintained at all times.***

  This significantly slows the rate at which work can progress due to the stop/start nature of the restrictions and the fact that safe access must be maintained at all times.

- transporting the transformers to site must be undertaken outside of business hours as street closures (and associated after hour traffic management and delivery costs are incurred) are required during the delivery process

3.1.4 Victoria market transformer

The AER commented the VM transformer has 10 years until it reaches end of life based on CBRM output.

The VM transformer is highly utilised. This has resulted in higher-than-normal degradation (as discussed above), and means the consequences of this transformer failing, expressed in terms of risk cost, is high. The combination of these two factors mean it is prudent to replace this transformer in accordance with our risk monetisation modelling, notwithstanding its lower age compared to the other transformers proposed.

3.2 Revised proposal forecasts

Consistent with the reasons provided in this addendum, our revised proposed capital expenditure transformer replacements is set out in table 3.4.

Table 3.4 Capital expenditure forecasts: transformer replacement ($ million, 2019)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Revised proposal	3.8	5.0	4.2	2.6	0.9	16.4

Source: CitiPower

9 CP RRP ATT49