Supplying the Mt Cottrell area

Draft Project Assessment Report

June 2025

Contents

1 Overview

The area of interest for this report includes Mount Cottrell and the surrounding locales including established growth areas of Truganina to the east, Werribee to the south and Melton to the north. This area is located in the metropolitan Melbourne western growth corridor (west of Melbourne) and is an area of rapidly developing domestic subdivisions and commercial / industrial load centres.

Following the required public consultation phase for a Non-Network Options Report, published in August 2024, we have determined that no credible non-network solutions exist and hence have prepared this draft project assessment report which has been prepared in accordance with the Regulatory Investment Test for Distribution (**RIT-D**) requirements of the National Electricity Rules (**NER**) clause 5.17.4[1].

A new substation at Mount Cottrell (MTC) driven by customer loads, the subject of a separate and previous RIT-D process, is anticipated to be in operation in 2025 and this report has found that an upgrade of that site is likely to be the preferred option to service the needs of the area.

Powercor Australia now seek further feedback from stakeholders including registered participants, the Australian Energy Market Operator (**AEMO**), non-network providers, interested parties and persons on our demand side engagement register. Submissions are due by **29 July 2025**.

Powercor will consider all submissions received in response to this draft project assessment report before preparing a final project assessment report.

1 Version 230 of the Rules, clause 5.17.4.

2 Background

2.1 The load area around Mt Cottrell

The western growth corridor (west of Melbourne) is an area of rapidly developing domestic subdivisions and commercial / industrial load centres.

The area of interest for this report is includes Mount Cottrell and the areas around it, including established growth areas of Truganina to the east, Werribee to the south and Melton to the north.

A new substation at Mount Cottrell (MTC) driven by customer loads is anticipated to be in operation in 2025. The establishment of MTC is the subject of a separate completed RIT-D process. It is established as a single transformer station, designed for supply to some large industrial customers.

The Mount Cottrell area will require significant infrastructure to service the developments as they occur and the new substation MTC is in a central location between four existing substations, Werribee (WBE), Laverton (LV), Truganina (TNA) and Melton (MLN). MLN and TNA are currently supplied by DPTS, whereas WBE and LV are supplied by Altona terminal station west (ATS west).

A map showing the area and relevant substations is shown in Figure 1.

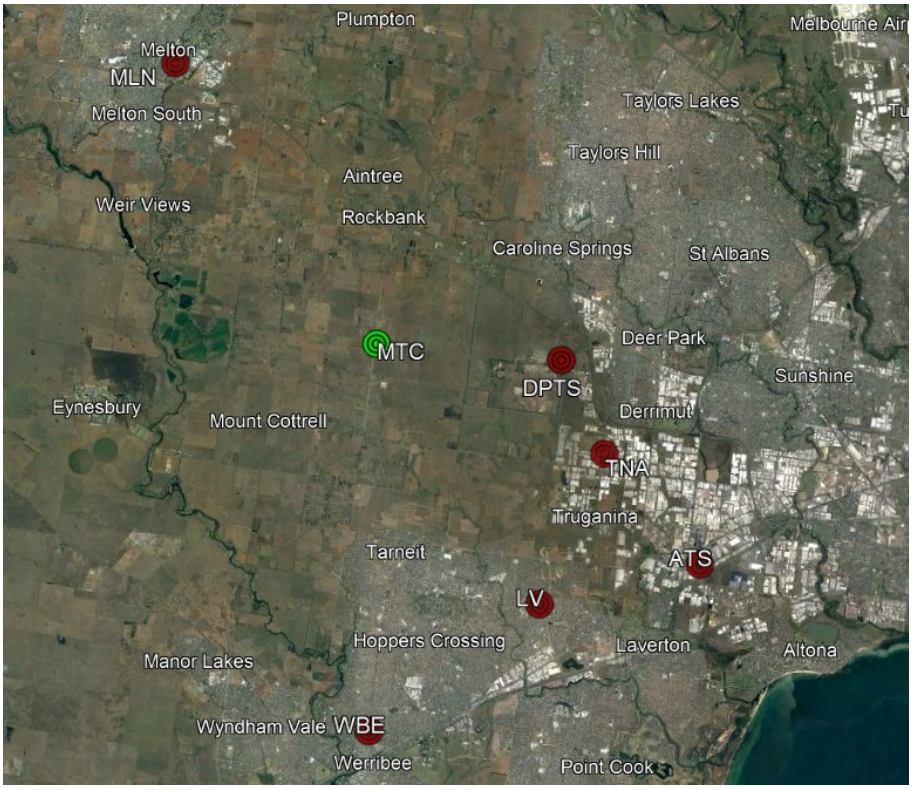

Figure 1 Mount Cottrell (MTC) supply area

In all network cases not using MTC as part of the solution, the distribution network in the rural areas around MTC (shown in Figure 2), would require upgrading to transport energy to, from or through the local region.

In any case, new infrastructure will be required to reticulate new commercial and or residential connections that will develop in the future.

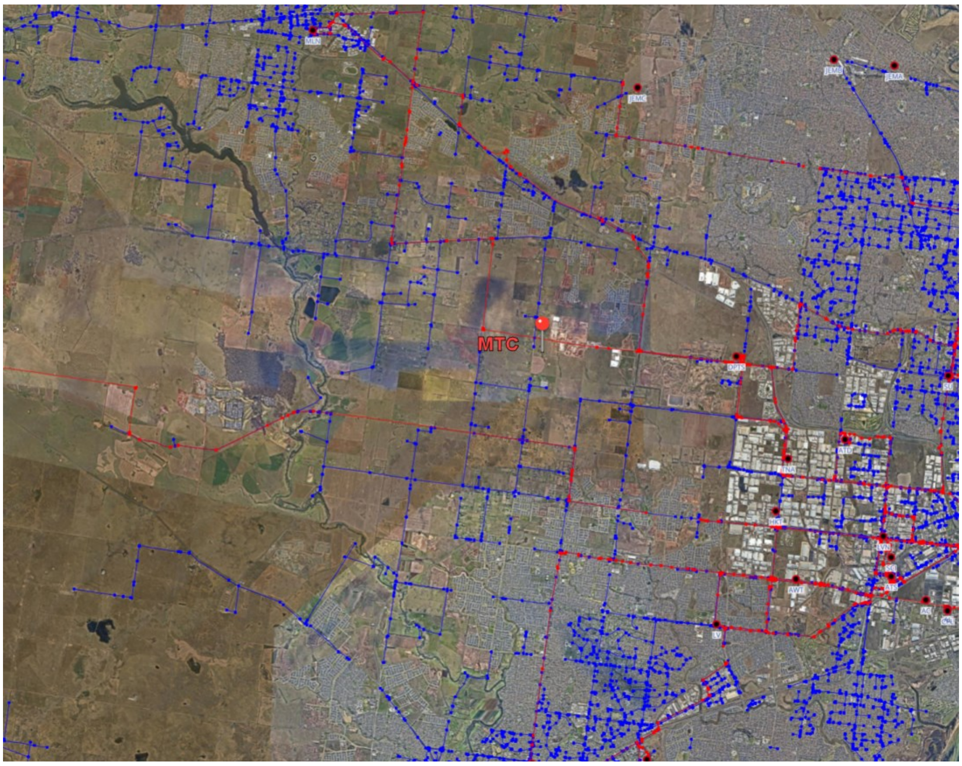

Figure 2 Sub transmission and distribution networks in the greater Mount Cottrell area

2.2 Application of the Regulatory Investment Test – Distribution (RIT-D)

Having a project value for a network solution in excess of $6m, this project meets the criteria of clause 5.17.3 of the NER and as such is subject to a RIT-D.[2]

We published a non-network options report (NNOR) in accordance with clause 5.17.4(b) of the NER in August 2024. The required consultation period for that report has now concluded and we have not found any viable non-network options that address the growth in this area. Accordingly, this Draft Project Assessment Report (DPAR) forms the next step of the RIT-D process.

[2] https://www.aer.gov.au/industry/registers/resources/reviews/cost-thresholds-review-regulatory-investment-tests-2021

3 Identified Need

The three substations, WBE, LV and MLN are all facing load constraints in the near future preventing them from being able to supply the forecast additional load in the areas supplied by them, and, unable to accept transfer requests from each other for operational needs. The terminal station ATS is also approaching load constraints, creating load at risk at all four sites.

The new substation at Mount Cottrell (MTC), being built to supply known commercial loads, will not have adequate capacity to accept additional load transferred from the surrounding existing substations. Consequently, in its designed state, MTC cannot alleviate the approaching constraint at ATS.

3.1 Identified need

Key factors driving the need for a solution include emerging no prior outage ('N') hours at risk at WBE, as well as significant levels of single outage ('N-1) hours at risk at TNA and ATS West.

Under Chapter 5 of the National Electricity Rules (NER), we are required to connect customers and in doing so, we must achieve the specified performance standards. Customers must be connected such that it will not adversely affect other registered participants.

We therefore consider the identified need for this investment to be 'providing adequate customer supply' under the RIT-D, as the investment is required to comply with the above NER obligations.

Timing is discussed in section 3.2 and the first critical date for an 'N' constraint is likely to occur in 2026.

3.2 Quantification of identified need through load forecasting

Each substation site has:

- a Nameplate and cyclic rating for when all components are in service in a normal operating configuration (N).
- a Nameplate and cyclic rating for when the operating configuration of a substation is such that if no more primary equipment can be taken out of service, intentionally or otherwise, without causing an interruption of supply to connected customers (N-1).

The allowed demand cyclic ratings are higher than nameplate ratings by implementing managed periods of overloading (cycling), allowing more energy to be delivered at a rate higher than full time loading limitations. This situation cannot be implemented permanently without damaging the equipment.

The forecast charts will show two probabilities of load growth (Probability of Exceedance or POE):

- 10% POE is the highest forecast result with a probability of 10% of this scenario being exceeded (less likely but possible), and,
- 50% POE, a more likely outcome of load forecasting which forms the basis of assessment in this report.

Load forecasts and typical consumption profiles are shown in the next sections, with data sourced from our 2023 Distribution Annual Planning Report (DAPR). A 'Central' load forecast was formulated for zone substations where there were high confidence customers looking to connect. The 'Central' load forecast is based on the 'High DER' load forecast as per the 2023 DAPR, with the addition of these diversified high confidence loads.

i. Mount Cottrell Substation (MCT) (to be commissioned in 2025)

Mount Cottrell is a substation that will be built and commissioned in 2025. It is the subject of a separate determination as it is a solution for customer funded load expansions and will be sized accordingly with one 25MVA transformer for that need and required level of supply security.

There is limited inter-substation network capability to allow transfers to and from MTC, with the main potential coming from Truganina which will have a small part of its load transferred to MTC as part of customer upgrades driving the MTC substation need.

The forecast for MTC is flat over the next 10 years with an anticipated demand of 18 MVA. This is a result of the dedicated function to supply a small number of large customers.

ii. Melton Substation (MLN)

MLN services domestic and commercial loads situated to the north of Mount Cottrell area. As shown in Figure 3, in all cases the N-1 cyclic rating is now exceeded, and the 50% POE “N” rating is forecast to be exceeded after 2031.

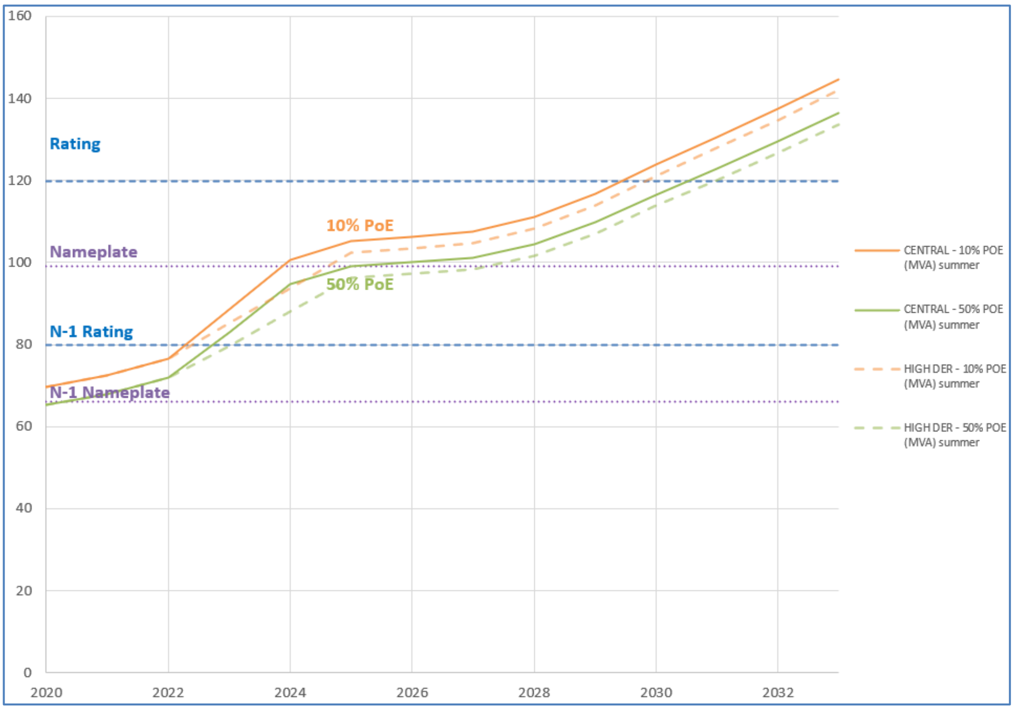

Figure 3 Melton Substation (MLN) Summer loading Forecast (MVA)

iii. Laverton Substation (LV)

LV supports a growing number of commercial and residential loads in the Tarneit region southeast of Mount Cottrell. As shown in Figure 4, this substation currently exceeds its N-1 rating and the load forecast is that it will reach its station 50% PoE "N" cyclic rating by 2031.

Figure 4 Laverton Substation (LV) Summer Loading Forecast (MVA)

iv. Truganina Substation (TNA)

TNA supplies domestic and commercial loads southeast of the Mount Cottrell area. As shown in Figure 5Figure 4, this substation currently exceeds its N-1 rating and the load forecast is that it will reach its station 50% PoE Central “N” cyclic rating beyond 2033. This extended constraint timing is due to transfer of some load into the new Mount Cottrell substation (MTC) on its completion post 2024.

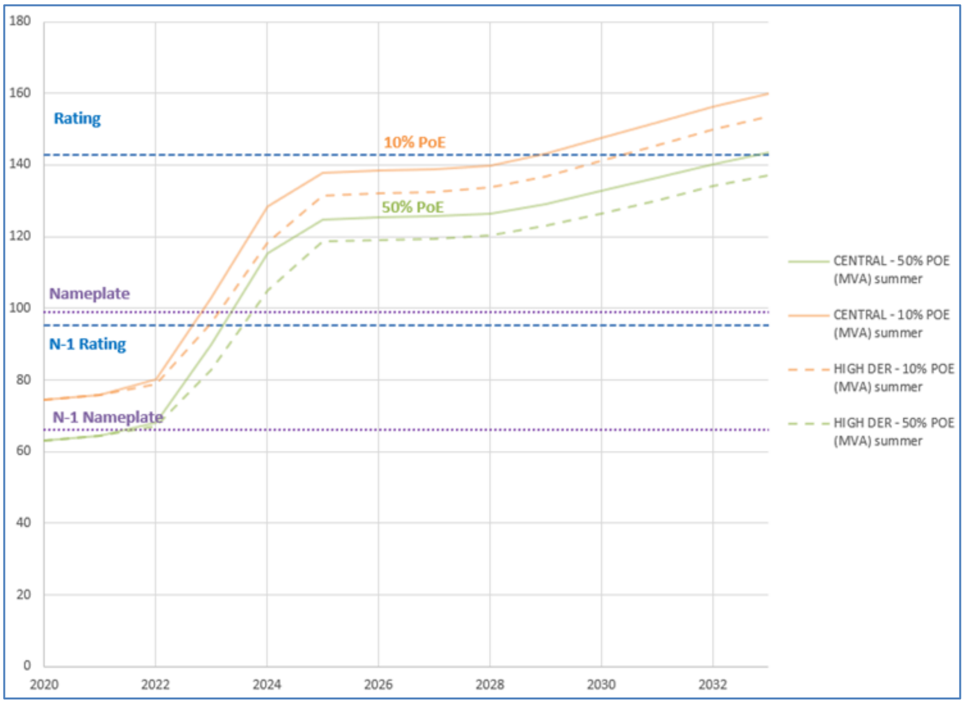

Figure 5 Truganina Substation (TNA) Summer Load Forecasting (MVA)

v. Werribee Substation (WBE)

WBE supports a rapidly growing number of commercial and residential loads in the region south of Mount Cottrell. As shown in Figure 6, this substation currently exceeds its 50% POE N-1 cyclic rating and the load forecast shows that it will likely reach its station 50% PoE "N" cyclic rating somewhere around 2026.

WBE has little to no peak transfer capacity available beyond 2023 to support other substations in this western growth corridor.

Figure 6 Werribee Substation (WBE) Summer Loading Forecast (MVA)

Summary of impacts of forecasts

As shown above in the peak demand forecasts (Figure 3 to Figure 6), electrical demand growth in the western growth corridor area is expected to continue in the short to medium term (and beyond). Each exceedance of N-1 capacity can result in us not meeting required quality of supply standards during system normal configuration as well as limiting ability to carry out maintenance and inspection tasks.

This is an immediate issue for WBE, LV and MLN, and Table 1 provides a summary of exceedances of the N and N-1 ratings exceedances (constraints) for each substation in this western growth area.

Table 1 Summary of rating exceedance timing (50% POE)

Substation	Exceed N-1 rating	Exceed N rating
MLN	**now**	**2031**
LV	**now**	**2031**
TNA	**now**	**2033**
WBE	**now**	**2026**

As peak demands increase, the N cyclic thermal ratings of all substations surrounding MTC will be exceeded, with a major concern in the Werribee area where overloading is likely to occur within the next 2 to 3 years. Unaddressed overloads beyond the cyclic N ratings are likely to see interruptions to customer supply occur, either unplanned or on a rotating load shedding arrangement.

4 Assumptions and Methodologies

4.1 Demand Forecasts

The demand forecasts are sourced from our DAPR which are then combined with the addition of recent high confidence non-committed loads.

4.2 Financial model inputs

In preparing our costs we have assumed:

- That the costs for works estimated by us will be within an accuracy of ± 10%. They are prepared by our internal estimators from standard component estimates.
- The models are evaluated over a period of 15 years.
- Calculations for annual deferral values of projects are based on our regulated pre-tax real Weighted Average Cost of Capital (WACC) as prescribed by the AER for the current regulatory period. The identified need described in this Non-Network Options Report occurs in the 2021-2026 regulatory reset period, where a WACC of 2.75% has been used to demonstrate an approximate WACC-driven deferral value below.

4.3 Market Benefit Classes

NER clause 5.17.1(c)(4) requires Powercor as the RIT–D proponent to consider whether each credible option can deliver specified classes of market benefits. These are shown in Table 2 along with our assessment of whether the market benefit class is relevant and material for this project.

Table 2 Market Benefits; assessment of materiality

Specified Class[3]		Material	Comments
1	Changes in voluntary load curtailment	No	Magnitude of load to be curtailed becomes large and not practical for management. Costs would be common across credible network options.
2	Changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers	Yes	Refer to section 4.4, Counterfactual case
3	Changes in costs for parties, other than the RIT–D proponent, due to differences in: the timing of new plant, capital costs, and operating and maintenance costs	No	Customer base makes this class not relevant hence immaterial.
4	Differences in the timing of expenditure	Yes	Addressed in economic analyses as part of the scenario analyses.

[3] Items 1 to 6 are from NER clause 5.17.1(c)(4) and items 7 to 10 are from the AER RIT-D application guidelines (section 3.6)

Specified Class[3]		Material	Comments
5	Changes in load transfer capacity and the capacity of embedded generators to take up load	No	Nature of the project make this class not relevant hence immaterial.
6	Any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the NEM	No	Nature of the project make this class not relevant hence immaterial
7	Changes in electrical energy losses	No	Consequences are real but not material in terms of comparison between options for network solutions.
8	Changes in fuel consumption arising through different patterns of generation dispatch	No	Nature of the project make this class not relevant hence immaterial
9	Changes in ancillary services costs	No	Nature of the project make this class not relevant hence immaterial
10	Competition benefits	No	Nature of the project make this class not relevant hence immaterial

4.4 Counterfactual case

If no action is taken to address the identified need (the counterfactual case), customer reliability is likely to be compromised and hence a cost of energy at risk will follow. While this is not a realistic option if the identified need is to be met, it allows calculation of the worst-case scenario for defining market benefits associated with involuntary load shedding.

The Value of Customer Reliability (VCR) for the energy at risk of the required loads is modelled using values shown in Table 3:

Table 3 Value of Customer Reliability by sector[4]

Sector	$/kWh
Residential	$ 25.13
Agricultural	$ 44.40
Commercial	$ 52.20
Industrial	$ 74.79

[4] https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20customer%20reliability%20%20update%20summary%20-%20December%202022.pdf

Given that the number of customers and their sector type connected to each substation are known, a mathematically derived VCR for each substation can be used. These values are shown in Table 4.

Table 4 VCR by substation ($/kWh)

Zone substation	MLN	LV	TNA	WBE	DPTS	ATS
ZSS VCR ($/kWh)	$ 37.73	$ 38.87	$ 51.06	$ 38.71	$ 46.11	$ 39.27

When the values in Table 4 are applied to substation forecasts over the next 15 years, a total VCR for each substation can be estimated. The results using a discount rate of 2.75% (including a total of the affected substations) is shown in Table 5.

Table 5 Discounted VCR modelled across the 15 year period

Substation	$M
MLN	50.7
WBE	294.6
TNA	21.0
LV	41.6
TOTAL	**408.0**

The significantly higher VCR for WBE in Table 5 reflects the almost impending 'N' constraint as discussed in section 3.2

Adjusting the discount rate between 1.5% and 4.5% gives an accumulated value across the modelling period between as shown in Figure 7:

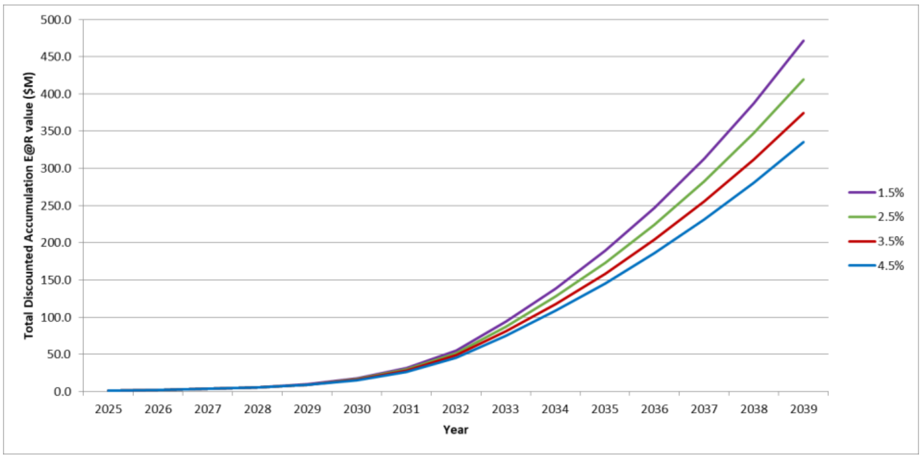

Figure 7 Accumulated cost of counterfactual case energy at risk

The results of discount rate scenario modelling gives a range of accumulated cost of non-supply to customers from $335m to $470m. Using the discount rate from section 4.2 gives a value of $408m, and it is this value that will be used in section 6.1.

5 Options to meet the identified needs

The network risks in section 3 and quantified in section 4. must be addressed. To not do so will compromise our ability to both provide supply to existing customers and connect new customers to the system, as required by chapter 5 of the NER.

5.1 Possible solutions

Connection to the existing distribution network will not be possible as forecasts show constraints emerging at all substations within and surrounding the area. Therefore, some form of augmentation or non-network solution will be required to enable the connection of the loads.

5.2 Determination of no non-network options

In accordance with clause 5.17.4 of the NER, Powercor must screen for non-network options as a solution for the identified need.

We undertook this process in August 2024 and, in accordance with NER clause 5.17.4(b), published our Non-Network Options Screening report entitled “Supplying the Mount Cottrell Area”.

After the mandatory consultation period required by the National Electricity Rules.

We did not receive any submissions that, for the identified need:

- provided a potential credible non-network option, or,
- formed a significant part of a potential credible non-network option.

The methodologies and assumptions that we have used to arrive at this conclusion are included in appendix A of this report.

5.3 Credible Network Options

There are possible network solutions to address the emerging load constraints in this area. The three most credible network solutions are:

a) Upgrade all surrounding substation sites

This option allows investment deferral via the upgrade of individual substations as emerging constraints at discrete sites are reached. There are difficulties with expansion at some sites, but for the RIT-D process, it is assumed that these problems can be resolved given appropriate focus.

This option does not transfer load from ATS west and as such the timing of its upgrade is not altered.

There is a need to upgrade connecting 22 kV feeders between substations to provide support to each other and to provide capacity to Mt Cottrell area. Centrally located MTC remains dedicated to industrial / commercial large loads.

b) Upgrade MTC to become a two transformer station and transfer other substation loads to it

This option requires a second 25MVA transformer to be installed at MTC, as well as accompanying distribution feeder connection points.

The central location minimises distribution connection work for inter substation load support. Transfer of load from other 3 substations to this central site will alleviate constraints from three existing substations. MTC is in the Deer Park Terminal station network and load transferred to it also alleviates the coming load constraint at ATS west, allowing deferral of the proposed ATS west upgrade.

c) Build new substation at Rockbank or Tarneit and transfer other substation loads to it.

   Our estimates for a Rockbank East substation showed that it was the lowest cost in building a new two transformer station,

   The option does require land purchase and construction of a new 2 transformer substation. There are also associated transmission and distribution connection works to allow the new substation to be connected to the grid.

   Similar to option b, transfer of load from other 3 substations to this new site will alleviate constraints from three existing substations and alleviates the constraint timing at ATS west, allowing the deferral of the upgrade proposed at ATS west.

Table 6 is a summary of these three credible network options that can address the identified need.

Table 6 Costing and Timing of Credible Network Options

Option	Description	Comments	Capital Value
(a)	Upgrade WBE, LV and MLN	• 3 substation sites to be upgraded as per constraint timing in Table 1 • Distribution mains into new developments • No change to timing of ATS west investment	\$32.6m - \$39.8m
(b)	Upgrade MTC	• 1 substation to be upgraded to add a second transformer bay and feeder circuit bays (2026) • Distribution network ties to be added (noting this brings forward distribution mains into new developments) (2026) • Transfer load from TNA, WBE, LV and MLN to MTC. This creates load transfers from ATS West to DPTS, deferring TS upgrades	\$15.9m - \$19.5m
(c)	New Substation at Rockbank east (RBE)	• Purchase land (2024) • Build new 2 transformer substation (2025) • Build connecting transmission and distribution power lines (2025) • Transfer load from ATS to DPTS deferring TS upgrades by one year	\$34.2m - \$41.8m

The net present value of each of these options and comparison to the counterfactual case is discussed in Section 6.

Our network studies show that to provide for adequate short and long term growth by a network solution, an upgrade of MTC will allow transfer of loads from other sites and provide capacity for continued local development of commercial and residential connections in the Mount Cottrell area.

6 Economic Modelling

In modelling the economic benefits of each of the options considered, the costs and benefits have been evaluated with reference to the counterfactual case. The modelled costs include the capital cost of implementing each option. Operations and maintenance costs for each option have not been included in the model as these are expected to be minimal for new assets over the 15-year modelling period and similar magnitude across options, hence non-material.

Market benefits include the customer value of the additional energy that will be able to be supplied as a result of implementing any of the options.

The net economic benefit of each option is calculated as the difference between the discounted value of the benefits and the costs over the 15-year modelling period.

In each case, a positive benefit over the counterfactual case of not investing in enabling these load connections is demonstrated.

6.1 Modelling results

a) The modelled financial results and subsequent preference ranking of the three options are shown in Table 7, where the costs and timing are from section 5.3, and the market benefits from section 4.4. As this project's identified need meets the definition of a reliability corrective action, clause 5.17.1 of the NER allows a negative net economic benefit. However, as the market benefits determined in section 4.4 are significant, all options are NPV positive.

Table 7 Model results for 2.75% discount rate

Option		Cost	Benefit	NPV	Ranking
(a)	Upgrade surrounding substations	$ 34.0m	$ 408m	$ 374m	3
(b)	Upgrade MTC substation	$ 16.8m	$ 408m	$ 391m	1
(c)	New substation RBE	$ 28.5m	$ 408m	$ 380m	2

Given the common market benefit value, sensitivity analyses will be viewed purely from a cost perspective.

6.2 Sensitivity analyses applied to options

The results of modelling shown in Table 7 will be influenced by changes in assumptions used within the financial evaluation model. As a result, the robustness of assumptions is tested through scenario modelling.

(i) Changing the discount rate in response to national economic conditions. Two values of -0.5% pa and +1% pa have been applied to the default rate with results shown in Table 8.

Table 8 Scenario results for varying Discount Rate

Option	Discount rate:	2.25%	2.75%	3.75%	Ranking
(a)	Upgrade surrounding substations	$ 35.3m	$ 34m	$ 31.6m	3
(b)	Upgrade MTC substation	$ 16.9m	$ 16.8m	$ 16.4m	1
(c)	New substation RBE	$ 28.6m	$ 28.5m	$ 28.1m	2

The ranking of the options does not alter with credible movements of discount rate, with option (b) remaining as preferred.

(ii) Returning the discount rate to 2.75%, the next variable to be modified is the load constraint timing for deferrable substations. The substation upgrades detailed in Table 1 will be brought forward or deferred to allow assessment of constraint timing impacts. Table 9 shows the effects on Options (a) by adjusting deferment timing of the zone substations by -2 years and +3 years. Note that this has little effect Options (b) and (c) as those options are required to service the load in 2025.

Table 9 Scenario results for increased deferment of load constraint timing in options (a) & (b)

Option	deferred by:	-2 years	0 years	+3 years	Ranking
(a)	Upgrade surrounding substations	$ 35.7m	$ 34m	$ 31.4m	3
(b)	Upgrade MTC substation	$ 17.2m	$ 16.8m	$ 16.8m	1
(c)	New substation RBE	$ 29.3m	$ 28.5m	$ 26.2m	2

Supply from MLN substation, Option (b) retains its status of preferred option under these scenarios.

(iii) Altering cost inputs for construction costs. Substations have a history of more predictable pricing than lines. As such, substation cost variances will be altered by +/- 10%.

Table 10 Scenario results for variations in cost inputs

Option	Cost base variation:	-10%	base case	+10%	Ranking
(a)	Upgrade surrounding substations	$ 30.6m	$ 34m	$ 37.4m	3
(b)	Upgrade MTC substation	$ 15.1m	$ 16.8m	$ 18.4m	1
(c)	New substation RBE	$ 25.6m	$ 28.5m	$ 31.3m	2

The ranking of the options does not alter with credible movements of discount rate, with option (b) remaining as preferred.

6.3 Discussion on results of modelling

Option (b) is the highest ranked option in all scenarios modelled in the sensitivity analyses. Given the similarity of the work involved with each option, the variables used apply equally to all options and as such the costs all move with a similar percentage difference from the base case.

The main exception to this is the ability to bring forward or defer augmentation of sites in option (a), but the cost associated with the number of sites overwhelms the impacts of discounted cashflow when compered to the other two options.

Option (c) will always be a higher cost than option (b) as it requires land purchase, control room and an extra transformer.

On average, option (b) has a 40% lower cost than second ranked result, option (c).

6.4 Preferred option

Clause 5.17.1 (b) of the NER defines the principle that the preferred option is to:

> *"maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market"*

The base case and all analyses modelled highlight that option (b) is the lowest cost option.

Therefore, Option (b) is identified as the preferred option of the credible and technically feasible options.

7 Satisfaction of RIT-D

The proposed preferred option as summarised in Section 6.4 satisfies the Regulatory Investment Test for Distribution. This statement is made based on the detailed analysis set out in this report.

Table 11 checklist of regulatory compliance

Rules clause	Requirement	Section of this report
5.17.4(j)(1)	Description of the identified need for the investment	Section 3
5.17.4(j)(2)	The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary)	Section 4
5.17.4(j)(3)	If applicable, a summary of, and commentary on, the submissions on the non-network options report	Section 5.2 & attachment A
5.17.4(j)(4)	Description of each credible option assessed	Section 5.3
5.17.4(j)(5)	Where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option	Section 4.4 & Table 2
5.17.4(j)(6)	A quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	Section 6
5.17.4(j)(7)	A detailed description of the methodologies used in quantifying each class of cost and market benefit	Section 4.4 & Table 2
5.17.4(j)(8)	Where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	Table 2
5.17.4(j)(9)	The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	Section 6
5.17.4(j)(10)	The identification of the proposed preferred option	Section 6.4
5.17.4(j)(11)	For the proposed preferred option, the RIT-D proponent must provide: • details of the technical characteristics • the estimated construction timetable and commissioning date (where relevant) • the indicative capital and operating cost (where relevant) • a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution • if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	Sections 3.2, Table 6, Table 12 Section 7 Not applicable
5.17.4(j)(12)	Contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	Section 8

8 Lodging a submission

We invite written submissions for non-network and or SAPS solutions to address the identified need in this report from any interested parties. Our aim is to develop the distribution network in a manner that maximises net economic benefits to all those who produce, consume and transport electricity in the National Electricity Market. We welcome submissions that may assist in this regard.

All submissions should include sufficient technical and financial information to enable us to undertake comparative analysis of the proposed solutions against alternative options. The proposals should include, but are not limited to, the following:

- Submissions must demonstrate response times, likelihood of success and any limitations that will be part of a proposed solution.
- Full costs of completed works including delivery and installation where applicable.
- Whole of life costs include operational costs.
- Project execution strategy including design, testing and commissioning plans.
- Engineering network system studies and study reports.

Powercor will not be legally bound or otherwise obligated to any person who may receive this non-network options report or to any person who may submit a proposal. At no time will Powercor be liable for any costs incurred by a proponent in the assessment of this non-network options report, any site visits, obtainment of further information from us or the preparation by a proponent of a proposal to address the identified need specified in this non-network options report.

Submissions can be provided electronically to the email address provided below:

Attention: Mount Cottrell Stage 2

ritdenquiries@powercor.com.au

Alternatively, submissions may be lodged by mail to the following address:

Attention: Mount Cottrell Stage 2

Powercor Australia Limited

Locked Bag 14090 Melbourne Vic 8001.

Submissions may be published on our website. If you do not want your submission to be published, please state this at the time of lodgement.

All submissions are due on or before 17:00 on 29 July 2025.

Following our review of any submissions made, any option chosen to address the identified need will be set out in the draft project assessment report required by the RIT-D assessment process.

We intend to complete our review of submissions and the selection of the final project assessment report by 29 July 2025.

9 APPENDIX

A Financial building blocks

B Glossary of terms

A Technical detail

A.1 Building block costs for financial modelling

Table 12 Cost building blocks (2022 pricing, capital costs unless noted otherwise))

Item	Unit cost	Comments	Life
Mini Zone substation	$ 30 M*	1 x 33 MVA transformer Switchgear, land, fencing, HV & LV connections	40+ yrs
Zone Substation	$ 45 M	2 x 33 MVA transformer Switchgear, land, fencing, HV & LV connections	40+ yrs
Additional transformer bay	$ 7.8 M	33 MVA transformer Switchgear, HV & LV connections	40+ yrs

** It is anticipated that one of the two mini zone substations would require significant additional cost to address the transmission connections, but this is ignored for now until model results indicate that the extra effort for accuracy is required.*

B Glossary of terms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DAPR	Distribution Annual Planning Report
DNSPs	Distribution Network Service Providers
HV	High Voltage
N rating	Capacity available with network operating with all elements in service
N-1 rating	Capacity available with network operating with one element unavailable for service
NER	National Electricity Rules
PoE 50	The 50% PoE demand forecast relates to maximum demand corresponding to an average maximum temperature that will be exceeded, on average, once every two years
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of customer reliability