Emerging Load Constraint; Altona Terminal Station (West)

Project Specification Consultation Report

October 2024

Contents

1 Overview

The Altona Terminal Station is located west of Melbourne in the Western Growth Corridor.

Altona Terminal Station West is the description used to identify a section of the Altona Terminal Station that utilises two dedicated transformers (and bays and associated equipment) as transmission connection assets to supply the local Powercor network.

The Altona Terminal Station West cannot take out one transformer for maintenance without overloading the second transformer. In addition, load forecasting has identified an emerging constraint where the station load will exceed transformer short term loading capacity at times of peak demand.

This report has identified one credible network option to mitigate the current, and emerging constraints, but acknowledges there may also be credible non-network solutions that could be developed.

Implementation of a solution must occur before the deterministic constraint timing of 2033. However, using probabilistic planning processes, it may be more efficient to implement a solution in 2029. This will depend on the cost and benefits of the preferred solution identified through the RIT-T process.

Powercor is now seeking 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 3 January 2025.

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

2 Background

2.1 Configuration of the local transmission network

The physical locations of Altona Terminal Station (ATS) and Brooklyn Terminal Station (BLTS) are shown in Figure 1. ATS is supplied by the 220kV network from BLTS.

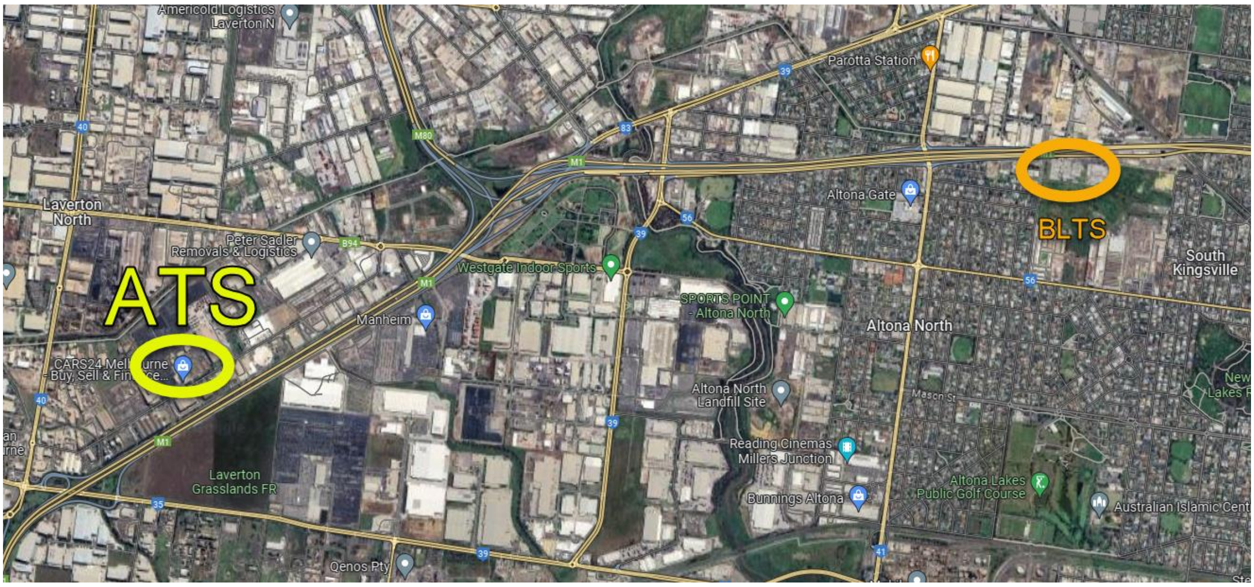

Figure 1 Location of Altona Terminal Station

For reliability and maintenance of existing supply requirements, Altona Terminal Station (ATS) is configured so that one transformer operates in parallel with the Brooklyn Terminal Station (BLTS) system and is isolated from the other two transformers via a permanently open 2-3 bus tie circuit breaker at ATS.

This electrically separates the secondaries of the two systems and effectively creates two separate terminal stations that share physical space at ATS. These operational arrangements are referred to as ATS/BLTS and ATS West.

This report is focused on constraints of the ATS West.

2.2 Altona Terminal Station West[1]

Altona Terminal Station West (ATS West) comprises two 150 MVA 220/66 kV transformers.

It supplies part of Melbourne's western growth corridor. This includes Laverton, Laverton North, Altona Meadows, Werribee, Wyndham Vale, Mount Cottrell, Eynesbury, Tarneit, Hoppers Crossing and Point Cook.

The station supplies approximately 100,000 customers, including a major customer connection supplied directly from its 66 kV bus.

A total of 145 MW capacity of embedded generation is installed on the distribution system connected to at ATS West. It includes:

- 20 MW of large-scale embedded generation; and

[1] Data from the 2023 Transmission Connection Planning Report, pp55-61

- 125 MW of rooftop solar photo-voltaic (PV), including residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

2.3 Powercor as the transmission connection planner

ATS West connection assets exist solely to supply the distribution network. The 2023 Transmission Connection Planning Report (TCPR) describes the Victorian joint planning arrangements for transmission connection assets and identifies Powercor as the responsible proponent for this project.

2.4 Application of the Regulatory Investment Test – Transmission (RIT-T)

Section 1.2 of the TCPR documents where Victorian distributors and AEMO have agreed that joint planning projects involving transmission connection and distribution investment should be assessed by applying the RIT-T.

This project is not an actionable ISP project hence Rule 5.16 applies to this project[2]. At the time of production of this report, the current version of the National Electricity Rules (NER) is version 216, commencing 05/09/2024.

Having a project value for a network solution more than $7 million[3], this project meets the criteria of rule 5.16.3 of the NER requiring a RIT-T.

This report forms the Project Specification Consultation Report (PSCR) required under rule 5.16.4.

[2] The term Rule refers to the National Electricity Rules

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

3 Identified Need

ATS West is a summer peaking station. Its maximum demand reached 201 MW (208 MVA) in 2022-23 summer.

If one of the 150 MVA 220/66 kV transformers at ATS West is offline during peak loading times and the N-1 station rating is exceeded, the OSSCA[4] automatic load shedding scheme will act to reduce the load in blocks to within safe loading limits. Where possible, any load reductions that are greater than the minimum amount required to limit load to the rated import capability of the station, could be restored at zone substation feeder level in accordance with Powercor's operational procedures after the operation of the OSSCA scheme. It is noted that the possible load transfers away to ATS/BLTS and DPTS terminal stations in the event of a transformer failure at ATS West total 24 MVA in summer 2024.

3.1 Identified need

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

Under Chapter 5 of the NER, we must connect customers and in doing so, must achieve the specified performance standards. Customers must be connected such that their connection will not adversely impact other registered participants.

We therefore consider the identified need for this investment to be 'providing adequate customer supply' under the RIT-T, as the investment is required to comply with the above NER obligations. We also note that the identified need qualifies as Reliability Corrective Action.

Timing is discussed in section 3.2 and the first critical date for an 'N' constraint is forecast to occur in 2033.

3.2 Quantification of identified need through load forecasting

ATS West is a summer peaking station. Its maximum demand reached 201 MW (208 MVA) in 2022-23 summer.

Figure 2 shows the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings. Note export ratings are nameplate ratings. The chart shows a reduction in the 2021 actual maximum demand due to planned transfers of approximately 30 MW from the heavily loaded Laverton (LV) and Werribee (WBE) zone substations (supplied by ATS West) to Deer Park Terminal Stations (DPTS).

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal rating for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

[4] OSSCA is designed to protect connection transformers against transformer damage caused by overloads. Damaged transformers can take months to repair or replace, which can result in prolonged, long-term risks to the reliability of customer supply.

Load growth at ATS West is expected to remain strong due to high population growth and increasing commercial and industrial customer connection activity. Forecasts include the large load connection on the secondary bus at ATS West.

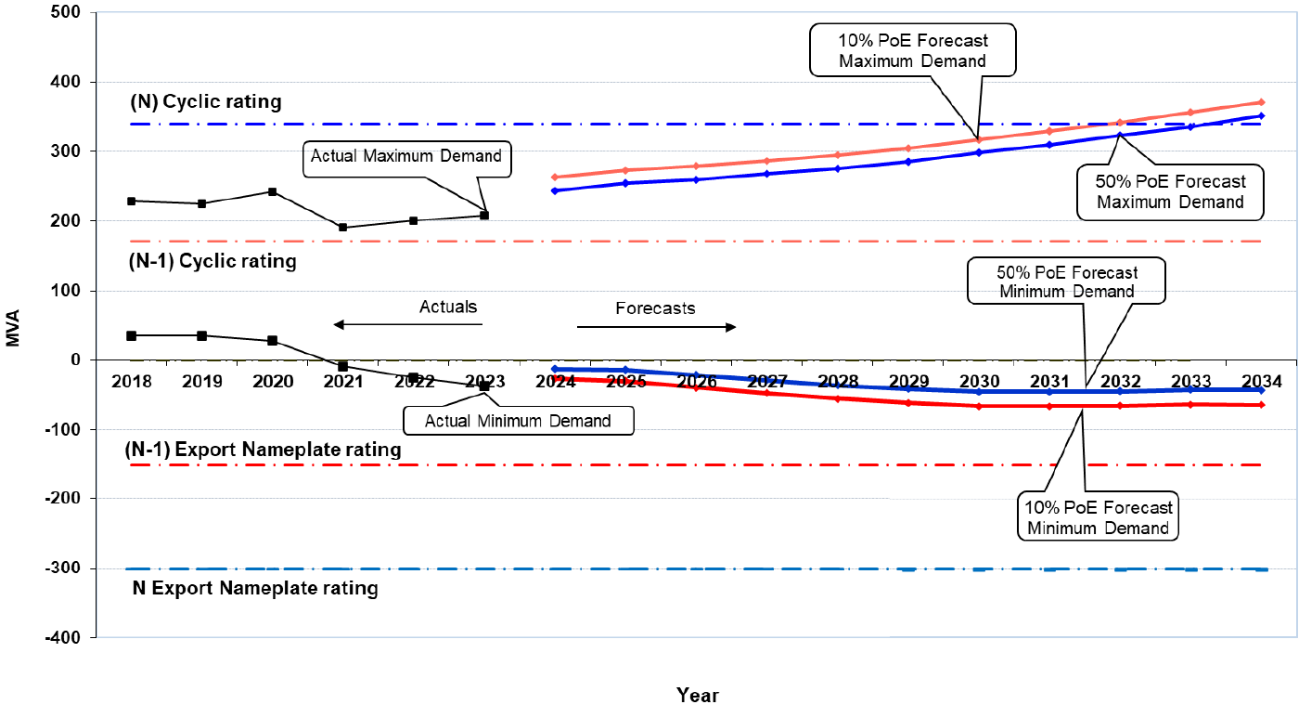

Figure 2 ATS West Maximum and Minimum Demand Forecasts

It is estimated that:

- for 7 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast (probability of exceedance or 50 POE)
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- for 1 hour per year, 95% of the minimum demand is expected to be reached.
- the station load power factor at the time of minimum demand is 0.99.

The "N" import rating on the chart indicates the maximum load that can be supplied from ATS West with all transformers in service. The "N-1" import rating on the chart is the load that can be supplied from ATS West with one 150 MVA transformer out of service.

3.3 Summary of impacts of forecasts

Electrical demand growth in the western growth corridor area is expected to continue in the short to medium term.

Figure 2 shows that:

- there is insufficient import capacity to supply the forecast maximum demand at POE50 at ATS West if a forced outage of a transformer occurs
- load has currently exceeded ability to take a transformer bay out of service for operational and or maintenance reasons
- forecast POE50 loads will exceed station capacity 2033.

This is an immediate issue for ATS West. Table 1 provides a summary of exceedances of the N and N-1 ratings exceedances (constraints) at ATS West.

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

Substation	Exceed N-1 rating	Exceed N rating
ATS West	**Now**	**2033**

3.4 Magnitude, probability and impact of loss of transformer (N-1 system condition)

The line graph in Figure 3 shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, based on the value of customer reliability (VCR) for this terminal station being $37,939 per MWh.

The bar chart in Figure 3 depicts the energy at risk with one transformer out of service for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating.

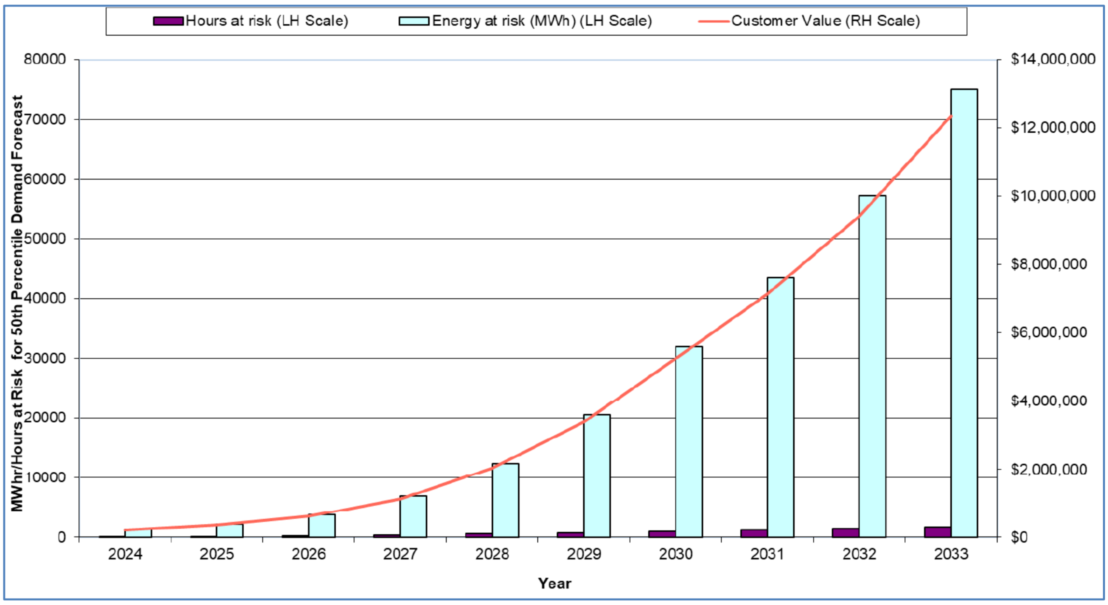

Figure 3 Annual energy and hours at risk and expected unserved energy at ATS West

Key statistics relating to energy at risk and expected unserved energy for 2029 under N-1 outage conditions are summarised in Table 2.

Table 2 Energy at risk and expected unserved energy in 2029

Scenario	MWh pa	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	20,528	$779 m
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	89	$3.37 m
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	26,695	$1,013 m
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	116	$4.39 m

Under the probabilistic planning approach[5], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%[6]) to determine the expected unserved energy cost in a year due to a major transformer outage[7]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

[5] Section 3 of the 2023 Transmission Connection Planning Report

[6] Section 5.4 of the 2023 Transmission Connection Planning Report

[7] The probability of a major outage of one transformer occurring is 1.0% per transformer per annum, refer to p57 of the 2023 Transmission Connection Planning Report

Table 2 presents estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[8]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2029 is $3.68 million.

Table 3 presents detailed data on system normal maximum and minimum demand forecasts and limitations over a 10-year period. Post 2033 is likely to have significant increases in energy at risk given the likely exceedance of the 50th percentile firm (N) capacity.

Notes for Table 3

Nameplate rating with all plant in service: 340 MVA via 2 transformers (summer)
Summer N-1 Station Import Rating: 170 MVA [See Note 1]
Winter N-1 Station Import Rating: 187 MVA
Summer N-1 Station Export Rating: 150 MVA [See Note 7]
Winter N-1 Station Export Rating: 150 MVA [See Note 7]

1. "N-1" means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 months. The outage probability is derived from the base reliability data given in section 5.4 of the 2023 TCPR.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2019 final determination, weighted in accordance with the composition of the load at this terminal station.

6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.
8. Red font indicates demand exceeding N-1 rating
9. White font on red background indicates demand exceeding N rating

[8] AEMO, Victorian Electricity Planning Approach, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

Table 3 System normal maximum and minimum demand forecasts and limitations (refer to preceding notes)

Import	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
50th percentile Summer Maximum Demand (MVA)	243.2	254.5	259.8	267.4	275.5	285.5	298.0	310.0	322.3	335.1
50th percentile Winter Maximum Demand (MVA)	202.1	216.2	228.5	241.8	256.9	272.6	289.4	303.2	317.3	333.5
10th percentile Summer Maximum Demand (MVA)	262.8	272.7	278.9	286.7	294.8	304.6	317.3	329.4	341.7	355.6
10th percentile Winter Maximum Demand (MVA)	208.9	223.2	235.6	248.9	264.2	280.4	297.5	311.6	325.5	342.1
N-1 energy at risk at 50th percentile demand (MWh)	1287	2211	3746	6885	12395	20528	31959	43503	57263	75086
N-1 hours at risk at 50th percentile demand (hours)	56.0	114.5	213.5	355.5	549.0	755.0	1003.5	1223.5	1450	1702.5
N-1 energy at risk at 10th percentile demand (MWh)	2301	3768	6110	10250	17031	26695	39815	52996	68027	88047
N-1 hours at risk at 10th percentile demand (hours)	91.0	183.5	303.0	467.5	672.0	892.0	1156.0	1395.0	1625.8	1909.8
Expected Unserved Energy at 50th percentile demand (MWh)	5.58	9.58	16.23	29.83	53.71	88.96	138.49	188.51	248.14	325.37
Expected Unserved Energy at 10th percentile demand (MWh)	9.97	16.33	26.48	44.42	73.8	115.68	172.53	229.65	295.61	395.17
Expected Unserved Energy value at 50th percentile demand	$0.21m	$0.36m	$0.62m	$1.13m	$2.04m	$3.37m	$5.25	$7.15m	$9.41m	$12.3m
Expected Unserved Energy value at 10th percentile demand	$0.38m	$0.62m	$1.00m	$1.69m	$2.8m	$4.39m	$6.55	$8.71m	$11.2m	$15.0m
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.26m	$0.44m	$0.73m	$1.30m	$2.27m	$3.68m	$5.64	$7.62m	$9.95m	$13.1m
Export	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10th percentile minimum Demand (MVA)	26.6	30.1	39.0	47.4	55.2	61.1	66.3	66.0	65.7	63.7
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

4 Assumptions and Methodologies

4.1 Demand forecasts

The demand forecasts are sourced from the 2023 Transmission Connection Planning Report.

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 ± 20%. They are prepared by our internal estimators from standard component estimates
- calculations for annual deferral values of projects are based on the discount rates from Table 31 of the AEMO Inputs, assumptions and scenarios report, with:
  - a lower bound rate of 4.69% based on Powercor's Weighted Average Cost of Capital (WACC)
  - a central rate of 7%
  - an upper bound rate of 10.5%.

4.3 2023 Transmission Connection Planning Report (TCPR)

The TCPR presents further information that underpin this report. Readers of this document should familiarise themselves with that document. Chapter 3 describes the planning methodology of the TCPR and chapter 4 documents inputs and assumptions for the TCPR. The information presented there has been used to determine energy at risk, expected unserved energy and value of customer reliability in this report.

5 Options to meet the identified needs

The network risks identified earlier in this report need to be managed. Failing to do so will compromise the ability to provide reliable supply to existing customers and connect new customers to the system as required under chapter 5 of the NER.

5.1 Non-network options

One purpose of this document is to provide information to proponents of non-network solutions regarding emerging network constraints, and thereby provide an opportunity for alternate solutions for the RIT-T project analysis.

Whilst not currently aware of any non-network solutions, we believe it may be possible to develop non-network solutions including:

- Demand reduction: there may be an opportunity to develop innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of potential demand reduction depends on the customer uptake and would be taken into consideration when determining the optimum timing of any network capacity augmentation.
- Embedded generation, connected to the ATS 66 kV bus, may substitute capacity augmentations. Alternatively, embedded generation at downstream location(s) such as our 66kV/22kV zone substation buses.

Table 3 provides quantification of emerging demand constraints and energy at risk that any non-network solution must address. Where a non-network proposal may form a partial solution that defers a network solution, details should be clear on how long that deferral is anticipated.

We aim to develop our network, and the associated transmission connection assets, in a manner that maximises net economic benefit. To this end, proponents of non-network solutions are encouraged to contact us if they are interested in obtaining more information to investigate non-network solution options.

To assist in the assessment of non-network solutions, proponents are invited to make a detailed submission. Submissions should include the following details:

(a) proponent name and contact details
(b) a detailed description of the proposal
(c) electrical layout schematics
(d) a firm nominated site
(e) capacity in MW and MVAr to be provided and number of units to be installed (if applicable);
(f) fault level contribution, load flows, and stability studies (if applicable)
(g) a commissioning date with contingency specified
(h) availability and reliability performance benchmarks
(i) network interface requirements (as agreed with us)
(j) the economic life of the proposal
(k) banker/financier commitment
(l) proposed operational and contractual arrangements that the proponent would be prepared to enter with us
(m) any special conditions to be included in a contract with us
(n) evidence of a planning application having been lodged, where appropriate.

All proposals must satisfy the requirements of any applicable regulatory codes or guidelines.

It is not likely that any non-network options will have material inter-network impact. An assessment of potential market benefits for non-network options are shown in Table 4.

5.2 Credible network options

We have identified a credible network option to alleviate the emerging network import constraint:

- install additional transformation capacity and reconfigure 66 kV exits at ATS, at an estimated indicative capital cost of $35 million to $45 million (equating to a total annual minimum cost of approximately $2.9 million). This would result in the station being configured so that three transformers are supplying the ATS West load (leaving existing arrangements unchanged at ATS for the one transformer to continue to provide capacity to the ATS/BLTS system). This option could be commissioned to meet constraint timing of 2033 at the latest and would require a construction period of 12 to 24 months.

For the purposes of this report, additional maintenance costs for this option are assumed to be 0.5% for the first 10 years and then 1% thereafter.

It is not likely that this option will have material inter-network impact. Market benefits for this option are assessed in Table 4.

5.3 Options considered but not progressed

We have identified a credible network option for alleviation of constraints that, while technically feasible, is not a better economic solution to mitigate the risk of supply interruption and/or to alleviate the emerging network import constraint:

- a new zone substation in the Tarneit or Rockbank East area supplied from DPTS to offload Werribee and Laverton zones substations load in the order of 40 MW. This will not eliminate the load at risk at ATS West, only reduce it – allowing for a deferral of investment at ATS West of 3 to 5 years. This is likely to have a capital investment approximating $30 million and could be constructed to meet constraint timing of 2033 at the latest. Construction would require 12 to 24 months.

However, acknowledging that a deferral is finite after which the option proposed in section 5.2 would be required allows an economic comparison to be made. This shows that at the upper bound discount rate of 10.5%, you would need the deferral to be 11 years (and the lower bound rate of 4.69% would need a deferral of 30 years). The size of the new substation in proposed in section 5.3 is expected to provide a 3-to-4-year deferral making this option less economical than the option proposed in section 5.2, hence this option is not progressed further.

5.4 Market benefit classes

Rule 5.16.4(b)(6)(iii) requires the RIT–T proponent to provide for each credible option, information about the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material. Table 4 provides our assessment of market benefits for this PSCR stage of the RIT-T. Note that the responses are applicable to the one identified network option as well as considering the potential on any possible non-network solution responses.

Table 4 Market Benefits; assessment of materiality

Specified Class[9]		Material	Comments
a	Changes in fuel consumption arising through different patterns of generation dispatch;	Unlikely	The project is a connection asset that has a small impact on market generation capacity. Any generation related solution would likely be a peaking plant.
b	Changes in voluntary load curtailment	Possible	This is dependent on the ability to develop a non-network solution.
c	Changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers	Yes	Refer to section 3.4.
d	Changes in costs for parties, other than the RIT–T proponent, due to differences in: the timing of new plant, capital costs, and operating and maintenance costs	Possible	This is dependent on what, if any, non-network solutions may be developed.
e	Differences in the timing of transmission investment	Possible	This is dependent on what, if any, non-network solutions may be developed. Some solutions may provide deferment of a network solution and economic analyses is required
f	Changes in network losses	Unlikely	This is dependent on the solution location. Any generation or network solution near ATS West site would likely see an insignificant change in losses between options, and, downstream embedded generation solutions will see an increased capital requirement because of likely multiple sites that would overwhelm loss savings
g	Changes in ancillary services costs	Unlikely	The project is a connection asset that has a small impact on the NEM.
h	Changes in Australia's greenhouse gas emissions	Unlikely	This project is a connection asset that has a small impact on Australia's greenhouse gas emissions.
i	Competition benefits, being net changes in market benefits arising from the impact of the credible option on participant bidding behaviour	Unlikely	The project is a connection asset that has a small impact on the NEM.
j	Any additional option value (meaning any option value that has not already been included in other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market	Unlikely	The project is a connection asset that has a small impact on the NEM.

[9] Refer to Paragraph 11 of the AER Regulatory investment test for transmission, August 2020 and Rule 5.15A.2(b)(4)

Specified Class[9]		Material	Comments
k	The negative of any penalty paid or payable (meaning the penalty price multiplied by the shortfall) for not meeting any relevant government-imposed instruments (such as the renewable energy target), grossed-up if not tax deductible to its value if it were deductible	Unlikely	The project is a connection asset that has a small impact on the NEM.
l	Other benefits that the RIT–T proponent determines to be relevant and are agreed to by the AER in writing before the project specification consultation report is made available to other parties	No	No other market benefits identified.

5.5 Draft conclusion

Rule 5.15A.2(12) requires the RIT-T to reflect that the credible option that maximises the present value of net economic benefit may, in some circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.

Only one credible network solution has been identified as discussed in section 5.2.

Therefore, in the event of no feasible efficient non-network solutions, this option would become the preferred option.

We note that the RIT-T process exists to further test this early finding.

6 Next steps

Powercor publishes this PSCR in accordance with the requirements of the NER, inviting submissions from interested parties.

A consultation period will apply, as required under rule 5.16.4(g) of the NER, of 12 weeks following the publishing of this report by AEMO on its website. The actual closing date is listed in Section 8 of this report, and submissions can be made using details supplied in that section.

We note that rule 5.16.4(z1)(1) of the NER permits an exemption from the Project Assessment Draft Report step of the RIT-T process if the capital cost is less than $46m[10]. The proximity of our estimated cost of the network solution to this cost threshold is within the estimate tolerances. This situation could see future refining of the estimated cost result in the preferred network solution cost exceeding the cost threshold.

As such, we have chosen not use the exemption allowed under rule 5.16.4(z1).

On completion of the consultation period, we will assess any submissions before continuing the RIT-T process to the next stage of a Project Assessment Draft Report.

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

7 Satisfaction of RIT-T

Table 5 Checklist of Regulatory Compliance

Rules clause	Requirement	Section of this report
5.16.4(b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	
5.16.4(b)(1)	Description of the identified need for the investment	Section 3.1
5.16.4(b)(2)	The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-T proponent considers reliability corrective action is necessary)	Sections 3, 4
5.16.4(b)(3)	the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	Section 3.4
5.16.4(b)(4)	if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	N/A Section 2.4
5.16.4(b)(5)	a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	Section 5
5.16.4(b)(6)	for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Section 5.2

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, including transmission connection assets, 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 information listed in section 5.1 of this report.

Powercor will not be legally bound or otherwise obligated to any person who may receive this project specification consultation 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: ATS West
rittenquiries@powercor.com.au

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

Attention: ATS West

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 03 January 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 31 March 2025.

9 APPENDIX

A. Glossary of terms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATS	Altona Terminal Station
ATS West	A portion of ATS dedicated as connection assets to the Powercor network
BLTS	Brooklyn Terminal Station
DAPR	Distribution Annual Planning Report
DNSPs	Distribution Network Service Providers
HV	High Voltage
ISP	Integrated System Plan
kV	kiloVolt (1000 Volts, a unit of electrical potential)
MVA	MegaVoltAmperes – unit of apparent power
MW	MegaWatts – unit of real power
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 (Version 216, 5th September 2024)
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
PSCR	Project Specification Consultation Report (this report)
PV	Photo Voltaic (Solar panels)
RIT-T	Regulatory Investment Test for Transmission
TCPR	2023 Transmission Connection Planning Report
VCR	Value of customer reliability