Emerging Load Constraint: Deer Park Terminal Station

Project Assessment Conclusions Report

January 2026

Contents

1 Overview

Deer Park Terminal Station (**DPTS**) is located west of Melbourne in the Melbourne West Growth Corridor.

DPTS has two dedicated transformers and associated equipment as transmission connection assets to supply the local Powercor network.

The most recently recorded peak demand on DPTS was such that if one transformer was out of service for any reason, it would not have been possible to supply all the load at the time of peak demand. The 10-year load forecast, which includes some committed major customer connections, indicates that by the summer of 2028/29 the station load will exceed transformer short term loading capacity with both transformers in service at times of peak demand.

One credible network option to mitigate the current and emerging constraints has been identified and following consultation one non-network solution has been proposed to mitigate the constraints.

Implementation of a solution must occur before the deterministic constraint timing of 2028/29, however using probabilistic planning processes, the cost to customers through the value of lost energy will exceed the annualised cost of investment associated with the preferred option in 2027.

This Project Assessment Conclusions Report has been prepared in accordance with the Regulatory Investment Test for Transmission (**RIT-T**) requirements of the National Electricity Rules (**NER**) clause 5.16.4[1].

[1] Version 243 of the Rules

2 Background

2.1 Configuration of the local transmission network

DPTS is located at the corner of Christies Road and Riding Boundary Road in Deer Park. It is connected into one of the three 220 kV circuits that connect Keilor Terminal Station (**KTS**) and Geelong Terminal Station (**GTS**). DPTS has two 225 MVA 220/66 kV transformers and has a nominal N-1 capacity of 225 MVA.

The station supplies more than 118,000 customers across Sunshine, Truganina, Tarneit, Laverton North, Caroline Springs and Melton.

The approximate current supply area of DPTS is shown in Figure 1.

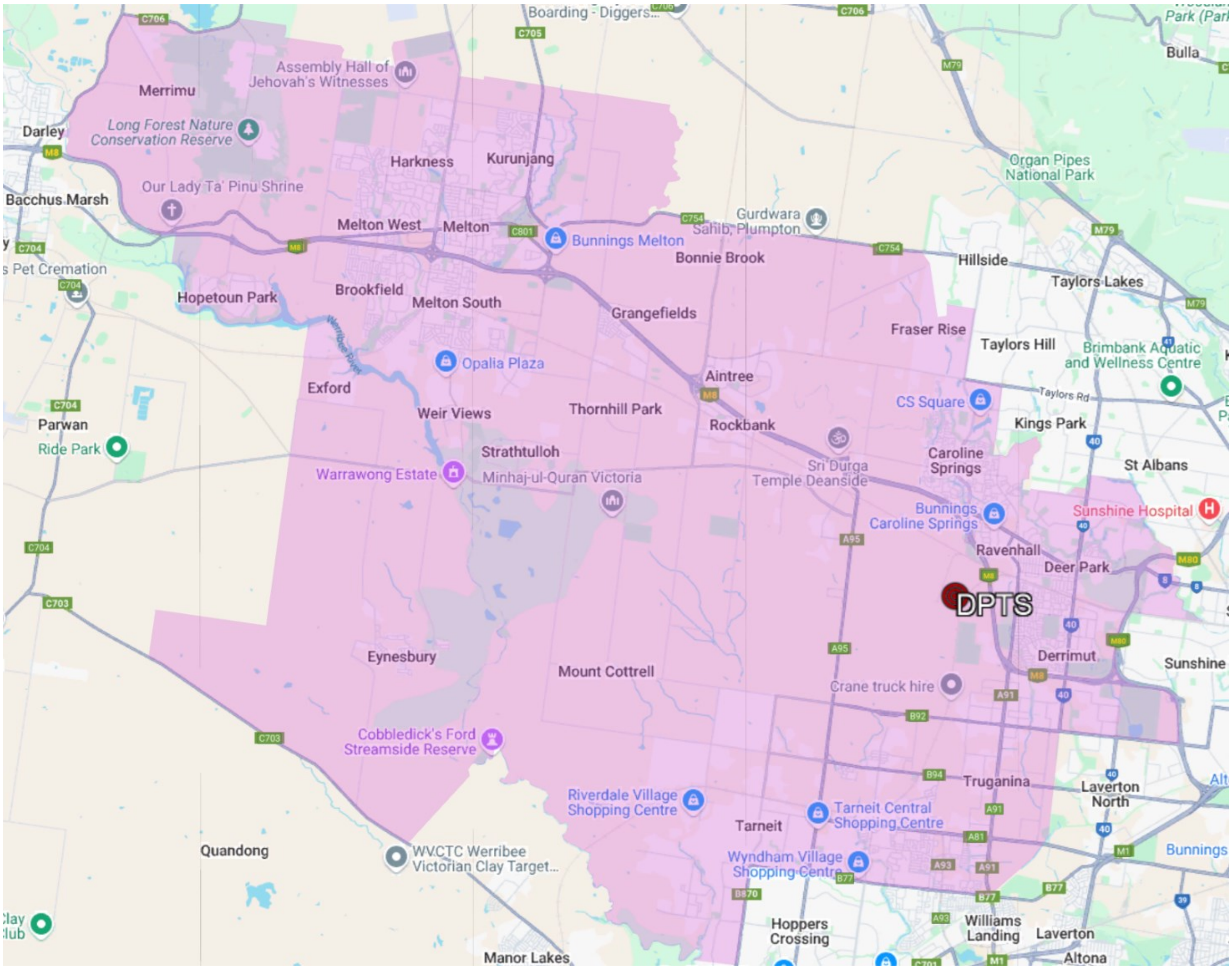

Figure 1: Geographic location of the supply area of Deer Park Terminal Station

2.2 Deer Park Terminal Station

A total of 220.4 MW of embedded generation is installed on the distribution system connected to DPTS. This includes:

- 14.4 MW of large-scale embedded generation
- around 206 MW of rooftop solar photo-voltaic (**PV**), including small-commercial and residential rooftop PV systems smaller than 1 MW.

2.3 Powercor as transmission connection planner

DPTS connection assets solely supply the Powercor distribution network. The Australian Energy Market Operator's (**AEMO**) Victorian Annual Planning Report (**VAPR**) describes the Victorian joint planning arrangements for transmission connection assets, and allocates responsibility for Powercor to act as the Regulatory Investment Test proponent for this project.

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

Section 1.2 of the Transmission Connection Planning Report (**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 Integrated System Plan (**ISP**) project hence clause 5.16 of the NER applies to this project[2]. At the time of production of this report, the current version of the NER is Version 243, commencing 1 January 2026.

Given this project has a value for a network solution larger than $8M[3], it meets the criteria under clause 5.16.3 of the NER and is hence subject to a RIT-T.

In June 2025, a Project Specification Consultation Report (**PSCR**) was published. We sought submissions on the PSCR in accordance with clauses 5.16.4 (d), (e), (f) and (g) of the NER. One confidential non-network option proposal was received which is discussed in section 5.1.

In December 2025, a Project Assessment Draft Report (**PADR**) was published and submissions sought in accordance with clauses 5.16.4 (o), (p), (q) and (r) of the NER. No submissions were received in response to the PADR.

This report is the final step of the RIT-T process, being the Project Assessment Conclusions Report (**PACR**) required under clause 5.16.4 of the NER.

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

[3] https://www.aer.gov.au/industry/registers/resources/reviews/2024-cost-thresholds-review-regulatory-investment-test

3 Identified need

DPTS is a summer peaking station with a firm (N-1) nameplate capacity of 225 MVA and an N-1 cyclic rating of 280 MVA. Its maximum demand reached 311.5 MW (324.9 MVA) in summer 2024/2025.

3.1 Identified need

Continued growth in demand across the network catchment area served by DPTS, including the proposed connection of the new Mt Cottrell Zone Substation (**ZSS**) and committed major loads have reduced capacity at DPTS during periods of high demand. The firm (N-1) capacity of DPTS has been exceeded and the energy at risk in the event of a transformer failure is forecast to become significant from 2027.

Chapter 5 of the NER requires us to connect customers, and in doing so, maintain compliance with regulated power system performance and quality of supply standards.

We therefore consider the identified need for this investment to be 'providing adequate customer supply' under the RIT-T given the investment is required to comply with the identified NER obligations. The identified need also qualifies as *reliability corrective action*.

The first critical date for an 'N' constraint is forecast in the summer of 2028/2029. More detailed discussion of the timing of the supply constraints, and the required timing of a solution to the identified need, is discussed in section 5.6.

For completeness, load growth at DPTS is forecast to result in a constraint on the 220 kV transmission network supplying DPTS. The work to remove this constraint is presented in this RIT-T as it is required to meet the needs of customers supplied from DPTS.

3.2 Quantification of identified need through load forecasting

Figure 2 provides a view of the import and export capacity of DPTS and the actual and forecast maximum and minimum demand to the end of the 10-year forecast period. The import capacity is based on the cyclic rating of the transformers, whilst the export rating is based on the nameplate rating, as advised by the asset owner.

In this figure, 'import' refers to energy being supplied from the transmission network to customers supplied from the low voltage side of DPTS. "Export" refers to energy being supplied from embedded generation across the DPTS network to the transmission network.

Load growth at DPTS is forecast to remain strong. This is driven by high population growth and the increasing number of commercial and industrial customer connections. Forecast demand includes committed load connections at DPTS.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the 10-year planning horizon.

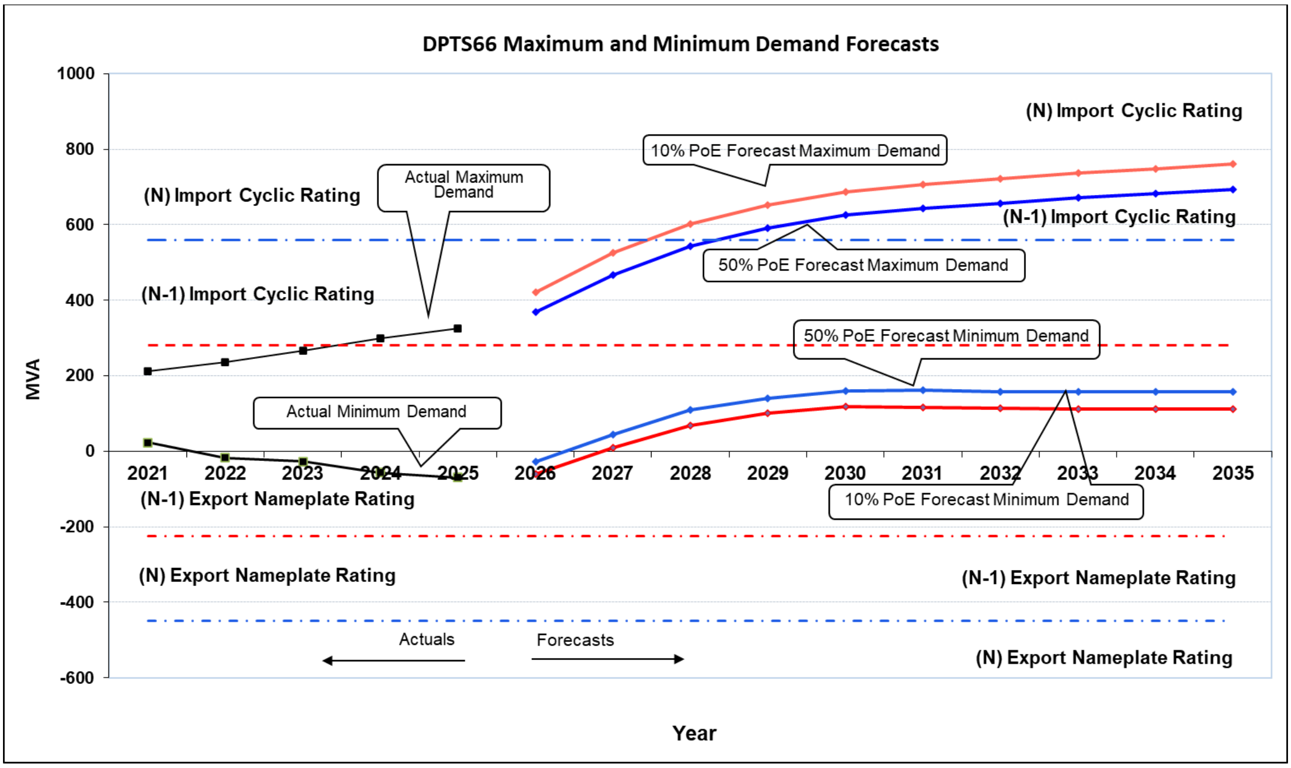

Figure 2: DPTS maximum and minimum historic and forecast load

Table 1: System normal maximum and minimum demand forecasts and limitations

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	367.9	466.1	542.2	591.2	625.5	643.7	657.5	671.5	682.9	693.5
50th percentile Winter Maximum Demand (MVA)	351.3	465.9	532.7	586.5	624.3	648.7	672.4	694.9	714.6	733.2
10th percentile Summer Maximum Demand (MVA)	421.9	525.3	601.7	651.9	686.9	706.0	721.6	736.6	749.1	761.1
10th percentile Winter Maximum Demand (MVA)	384.6	498.7	566.4	620.1	657.0	681.5	707.3	730.2	749.4	768.6
N-1 energy at risk at 50th percentile demand (MWh)	660	7717	23154	46153	71356	89743	108010	127911	146531	165497
N-1 hours at risk at 50th percentile demand (hours)	24	159	434	892	1348	1635	1895	2154	2400	2636
N-1 energy at risk at 10th percentile demand (MWh)	2548	16744	46208	83588	119225	144137	169925	196044	219507	243986
N-1 hours at risk at 10th percentile demand (hours)	66	320	886	1505	2035	2360	2674	2984	3244	3499
Expected Unserved Energy at 50th percentile demand (MWh)	20	232	695	1408	2247	2892	3566	4337	5095	5901
Expected Unserved Energy at 10th percentile demand (MWh)	76	502	1424	2713	4074	5091	6189	7380	8497	9723
Expected Unserved Energy value at 50th percentile demand	$0.8M	$9.2M	$27.7M	$56.1M	$89.6M	$115.3M	$142.1M	$172.8M	$203.1M	$235.2M
Expected Unserved Energy value at 10th percentile demand	$3.0M	$20.0M	$56.8M	$108.1M	$162.4M	$202.9M	$246.7M	$294.1M	$338.6M	$387.5M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$1.5M	$12.5M	$36.4M	$71.7M	$111.4M	$141.6M	$173.5M	$209.2M	$243.7M	$280.9M
Export	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
10th percentile minimum Demand (MVA)	60.5	9.4	69.3	100.7	118.7	116.4	113.5	112.2	111.1	110.9
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

Notes

Nameplate rating with all plant in service:	450 MVA via 2 transformers
Summer N-1 Station Import Rating:	280 MVA [See Note 1]
Winter N-1 Station Import Rating:	300 MVA
Summer N-1 Station Export Rating:	225 MVA [See Note 7]
Winter N-1 Station Export Rating:	225 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 Celsius.
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 2025 TCPR.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 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

3.3 Expected energy at risk

The line graph in Figure 3 displays the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the value of customer reliability (**VCR**)[4] for DPTS, which is $39,855 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.

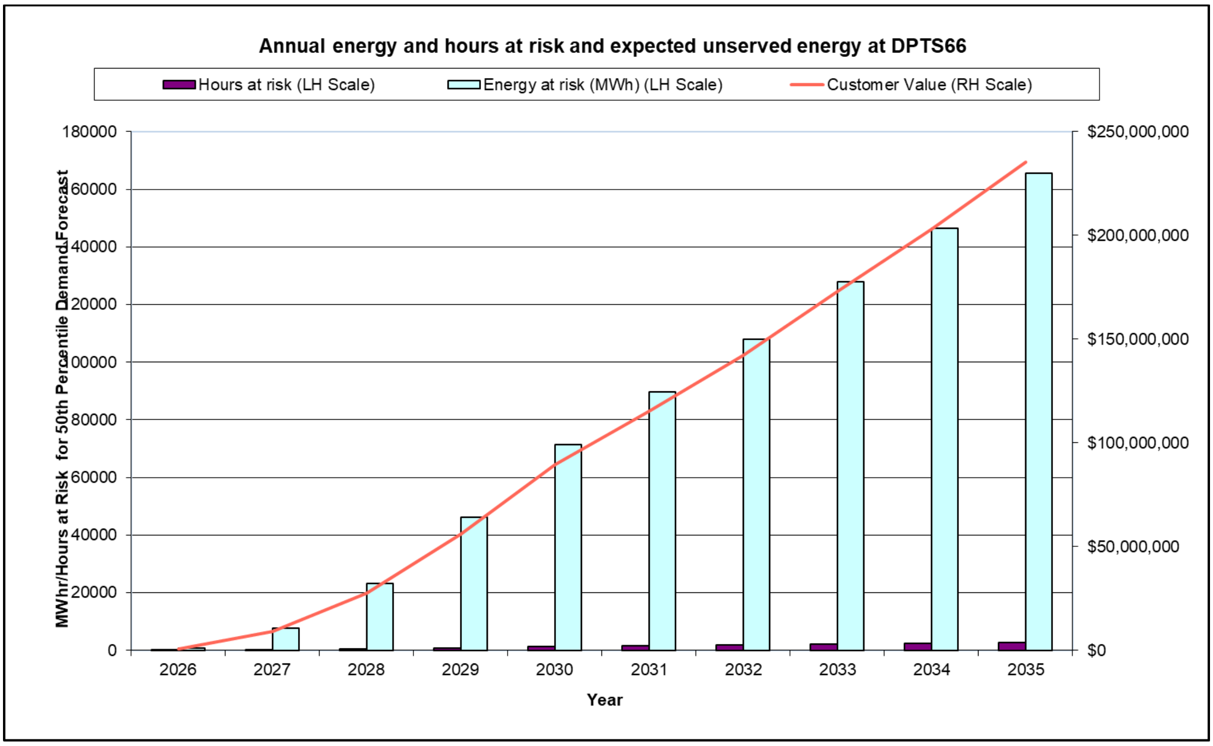

Figure 3: DPTS expected unserved energy

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 VCR is used to value the expected unserved energy, which is compared to cost of investment required to remove the energy at risk. When the annual value of the expected unserved energy exceeds the annualised cost of the mitigating investment it is economical to invest to remove the risk. Section 5.6 discusses the preferred investment timing based on this analysis.

[4] AER 2024 Values of Customer Reliability Annual Adjustment

[5] Section 3 of the 2025 Transmission Connection Planning Report

[6] Section 4.6 of the 2025 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 2025 Transmission Connection Planning Report

3.4 Summary of impacts of forecasts

Electrical demand growth in the western growth corridor area is expected to continue for the foreseeable future. Under the POE50 growth scenario:

- there is currently insufficient import capacity to supply the forecast maximum demand at DPTS if a forced outage of a transformer occurs
- similarly, there is insufficient import capacity to take a transformer bay out of service for operational and or maintenance reasons at times of peak demand, limiting opportunities for maintenance and operational flexibility
- by summer 2029-30 peak demand will exceed the import capacity of the station, potentially resulting in the need to shed load.

4 Assumptions and methodologies

4.1 Demand forecasts

The demand forecasts represent our most recent view of the demand across our network under both a POE50 (50% probability of exceedance) and a POE10 (10% probability of exceedance) scenarios. These forecasts include new major committed customer loads and the impact of network configuration changes, including the connection of the recently established Mt Cottrell ZSS to the DPTS 66kV bus.

4.2 Financial model inputs

In preparing our costs we have assumed:

- that the costs of the works estimated will be within an accuracy of ± 20 per cent. They have been prepared utilising AEMO's Transmission Cost Database
- calculations for annual deferral values of projects have been based on discount rates presented in table 31 of AEMO's Inputs, Assumptions and Scenarios Report[8], with:
    - a lower bound rate of 4.69%, based on Powercor's weighted average cost of capital (**WACC**)
    - a central rate of 7% and
    - an upper bound rate of 10.5%.

4.3 2025 Transmission Connection Planning Report (TCPR)

The TCPR[9] is the joint transmission connection planning report for Victoria. It is prepared by the five Victorian electricity distribution businesses, including Powercor, in accordance with the transmission connection planning requirements of clause 19.3 of the Victorian Electricity Distribution Code of Practice and clause 5.13.2 of the NER.

The TCPR contains the information that underpins the analysis in this PACR. Readers of this PACR should familiarise themselves with the TCPR. Chapter 3 describes the planning methodology used in the TCPR and chapter 4 documents the inputs and assumptions for the TCPR. The information presented there has been used to determine the energy at risk, expected unserved energy and VCR.

[8] https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

[9] 2025 Transmission Connection Planning Report

5 Options to meet the identified needs

If the network risks identified early in this PACR are not addressed, our ability to provide supply to existing customers, and connect new customers, as required by Chapter 5 of the NER will be compromised.

5.1 Non-network options

A confidential non-network option proposal was received to address the emerging load constraint at DPTS:

- the proposed size is 8.8 MW, with an expansion up to 40 MW firm capacity available no earlier than 2028
- the existing connection is our Truganina ZSS which is supplied from DPTS
- the proposal makes no substantive contribution to power system security, but does provide increased reliability of 8.8 MW up to 40 MW of proposed capacity
- the contribution to power system fault levels is not expected to exceed the fault current ratings of the circuit breakers in the Deer Park supply region
- the expected operating profile is a capacity factor of greater than 0.84 with an increased capacity factor likely after expansion.

At the existing size (8.8 MW), the capacity of the proposal does not materially defer the proposed network augmentation. With an expansion proposed for 40 MW in 2028, the expansion will not occur before the prudent timing of the proposed network option[10]. We therefore do not consider the proposal addresses the identified need or allows deferral of the network solution.

5.2 Load transfers

The load on DPTS can potentially be managed by permanently transferring load onto adjacent terminal stations that could possibly include Altona Terminal Station West (**ATS-WEST**), Altona-Brooklyn Terminal Station (**ATS-BLTS**) and Keilor Terminal Station (**KTS**). Transfers of load between zone substations using the 22kV distribution network is also possible.

To impact the demand on DPTS, transfers between zone substations require the load to be transferred to a zone substation supplied from another terminal station. The distribution network configuration is such that opportunities for this type of load transfer are minimal and will not have a material impact on the load at risk at DPTS. Temporary load transfers between zone substations may be used to manage reliability impacts in the event of a fault on the DPTS network.

Possible load transfers away to ATS-WEST, ATS-BLTS and KTS terminal stations in the event of a transformer failure at DPTS total 33.9 MVA in summer 2025/26.

Due to the low available spare capacity in the broader area, and the load growth in the area, load transfers only transfer load at risk between stations rather than alleviating it. Load transfers are therefore not a viable solution to the identified network need.

5.3 Credible network options

We have identified one credible network option to alleviate the network constraints and address the identified need. The option is technically feasible and considered efficient in mitigating the risk of a supply interruption and/or alleviating the emerging network import constraint.

The option involves the installation of an additional 225 MVA 220/66kV transformer at DPTS, at an estimated capital cost of approximately $20 million11. This would result in the station being configured so that three transformers are supplying the DPTS load. To avoid an overload on the existing 220 kV lines supplying DPTS, VicGrid, as the planner of the Victorian transmission network requires the two existing GTS-KTS 220 kV lines to

[10] If assumed to be available prior to the proposed augmentation the non-network option (40 MW), would defer for no more than 6 months

[11] AEMO Transmission Cost Database

be cut into DPTS as part of this network option to allow an increase in supply from the transmission network above the existing level at a cost of $66M12. The total cost of this option is approximately $86M. This option is not expected to have a material inter-network impact. Market benefits for this option are assessed in Table 2.

5.4 Options considered but not progressed

No other options were identified that may address the identified need.

5.5 Market benefit classes

Clause 5.16.4(b)(6)(iii) of the NER 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 2 provides an assessment of market benefits for this RIT-T. Note that the responses are applicable to the one identified network option, as well as for any non-network solution.

Table 2 Market benefits; assessment of materiality

Specified class[13]		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	Demand exceeding the N-1 capacity of the station initially and the N capacity shortly thereafter means involuntary load shedding will be required at times of peak demand. This will be alleviated by the preferred solution.
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 required

[12] AEMO Western-Metropolitan-Melbourne-Reinforcement-RIT-T-PSCR.pdf

[13] Refer to Paragraph 11 of the AER Regulatory Investment Test for Transmission, November 2024 and Rule 5.15A.2(b)(4)

Specified class[13]		Material	Comments
f	Changes in network losses	Unlikely	This is dependent on the solution location. Any generation or network solution near DPTS 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	The project is a connection asset that has a minimal impact on 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.
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.

5.6 Investment timing

The first critical date for an 'N' constraint is forecast to occur in the summer of 2028/2029. Work to alleviate the constraint must have occurred by then to avoid involuntary load shedding at times of peak demand.

The estimated capital cost of the preferred investment option is $86M. With a 45-year asset life and Powercor's allowance of 0.5% of the capital cost of the transformer for annual operations and maintenance costs, this equates to an annualised cost of $6.75M. An analysis of the energy at risk data in Table 1 demonstrates that by

2027, the value of the unserved energy exceeds the annualised cost of the investment required to mitigate the lack of capacity.

Table 3 shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under our probabilistic planning approach, we calculate 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)[14]. Applying this approach, the weighted average cost of expected unserved energy in 2027 is $12.5M. This is the first year when the value of the expected unserved energy exceeds the investment cost and indicates that 2027 is the optimum time to invest to mitigate supply being at risk.

Table 3 Energy at risk and expected unserved energy in 2027

Scenario	MWh pa	Valued at VCR ($M)
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	7717	308
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition[8]	232	9.2
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	16744	667
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition[8]	502	20

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

6 Economic modelling

In modelling the economic benefits of each of the preferred options, the costs and benefits have been evaluated by reference to the counterfactual case, in which no expansion of the network takes place and the load at risk continues to grow throughout the modelling period. The modelled costs include the capital cost of implementing each option, which is assumed to be expended over two years from 2027. The expected energy at risk in both the counterfactual case and the investment scenario is valued at a weighted average VCR across the relevant customer classes of $39,855 /MWh.

Over the modelling period, the operating and maintenance costs associated with the investment option are modelled using an allowance of 0.5% of the capital cost for annual operations and maintenance costs.

The net economic benefit of each option is calculated as the difference between the discounted value of the benefits and the costs over the 10-year modelling period.

Three scenarios have been modelled:

- an investment of $86M, with a 7% discount rate, being the central case
- an investment of $103M with a 10.5% discount rate representing the worst-case scenario
- an investment of $86M with a 4.69% discount rate, being our regulated WACC

The net economic benefit under each scenario is shown in Table 4.

Table 4: Economic benefit of modelled scenarios

Option	Investment cost ($M)	Discount rate (%)	Counterfactual NPV ($M)	Investment case NPV ($M)	Net benefit ($M)
1	$86.0M	7.00%	-$176.3M	-$97.0M	$79.3M
2	$103.0M	10.50%	-$143.3M	-$110.7M	$32.6M
3	$86.0M	4.69%	-$203.3M	-$98.9M	$104.4M

Under each scenario there is a net economic benefit to investing in a third transformer at DPTS to manage forecast load growth.

As net economic benefit of each option is calculated as the difference between the discounted value of the benefits and the costs over the 10-year modelling period, the terminal values are as follows:

1. $1,991M with a 7% discount rate, being the central case
2. $957M with a 10.5% discount rate representing the worst-case scenario
3. $3,696M with a 4.69% discount rate, being our regulated WACC.

6.1 Conclusion

Only one credible network solution has been identified, that is to install a third 225MVA 220/66kV transformer at DPTS and cut in two additional 220kV transmission lines to the DPTS, at an estimated capital cost of approximately $86M.

As no non-network solutions are identified that would be a more efficient solution, this option is the preferred option as per clause 5.16.4(8) of the NER.

7 Satisfaction of RIT-T

Table 5 Checklist of Regulatory Compliance

Rules clause	Requirement	Section of this report
5.16.4(v)	The project assessment conclusion report must include:	
5.16.4(k)(1)	A description of each credible option assessed.	Section 5
5.16.4(k)(2) 5.16.4(v)(2)	a summary of, and commentary on, the submissions to the project specification consultation report and project assessment draft report.	Section 5.1
5.16.4(k)(3)	a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option.	Section 5
5.16.4(k)(4)	a detailed description of the methodologies used in quantifying each class of material market benefit and cost.	Section 5.4
5.16.4(k)(5)	reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material.	Section 5.4
5.16.4(k)(6)	the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions).	Section 5.4
5.16.4(k)(7)	the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results.	Section 6
5.16.4(k)(8)	the identification of the proposed preferred option.	Section 6.4
5.16.4(k)(9)	for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics (ii) the estimated construction timetable and commissioning date (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	Section 5
5.16.4(k)(10)	RIT reopening triggers applying to the RIT-T project where the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination).	N/A, project less than $100M

A. Glossary of terms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DPTS	Deer Park Terminal Station
HV	High Voltage
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
POE10	The 10% PoE demand forecast relates to maximum demand corresponding to an average maximum temperature that will be exceeded, on average, once every two years
POE50	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
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PV	Photo Voltaic (Solar panels)
RIT-T	Regulatory Investment Test for Transmission
TCPR	2025 Transmission Connection Planning Report
VCR	Value of customer reliability