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Board Paper:	Red Cliffs Transformer Replacement
Meeting Date:	16 June 2026
For:	Decision
Sponsor:	[C-I-C], Executive General Manager, Transmission
Authors:	[C-I-C], GM Delivery; [C-I-C], GM Network Management

Red Cliffs Transformer Replacement - Regulated Expenditure

1. Executive Summary

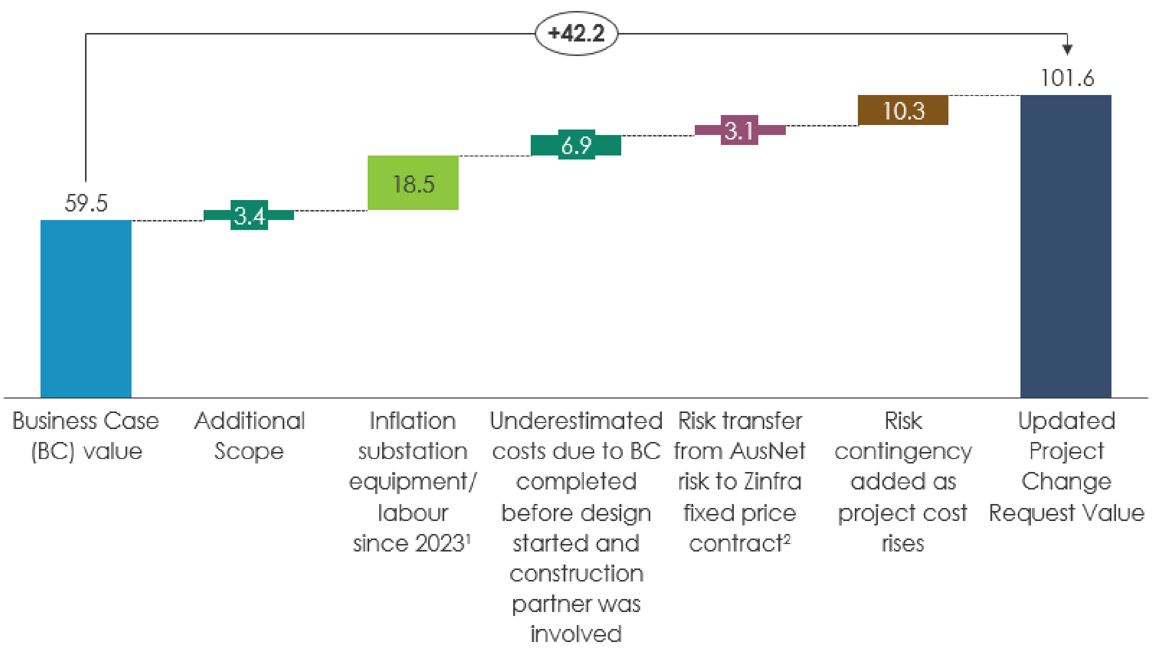
The Red Cliffs Terminal Station (RCTS) Transformer Replacement business case was approved by the CEO, under AusNet's Delegations of Authorisation (DoA), in September 2023 for a total investment value of $59.5M. The project mitigates safety, explosion, fire risks as well as the risk of interruption to customer power supply and large-scale embedded generation transmission by replacing 4 power transformers at RCTS commissioned in the 1960s to 1980s that are at advanced to extreme deterioration.

This project is currently in construction stage 1. Design has been completed, materials ordered, outages planned, site mobilised, U transformers delivered.

This paper seeks Board approval to amend:

- a scope change, adding 2 x 220kV ROIs / earth switches on B1 and B2 Circuit Breaker circuits required as per AusNet's standard (SDM 02-0302) for 220 kV dead tank circuit breakers.
- an additional $42.2M to replace Red Cliffs transformers, bringing the total expenditure to $101.6M. The original 2023 business case approval reflected the organization's estimating maturity and project approval process (Business Case approved prior to design starting) at that time, which has since improved. The cost increase is mainly driven by enhanced understanding of the project requirements, inflation in materials and labour contract costs, some additional scope.

Figure 1: Cost Increase Waterfall



[1] 55% inflation on substation construction costs from 2023-2026 as per AEMO cost analysis
[2] If risk transfer did not happen contingency increase would be larger covering 25% of increase

It is recommended that the Board approve the proposed increase in Project Budget from $59.5M to $101.6M, with the associated scope change. This is because:

- Revalidated needs case and options analysis – options to defer, descope or re-sequence increased whole life cost, safety & execution risk
- Schedule achievable within current AIS date (Nov 2028)
- Revised costs credible class one estimate - fixed construction price from [C-I-C] off a completed design, materials ordered. Risk workshop conducted, risk and contract costs independently assessed by consulting firm.
- Project cost can be accommodated within 5-year capital plan
- Commercial position sound [C-I-C]
- Approval delay would have material downside.
    - Miss outages moving work into congested period for network
    - Continued asset risk exposure to transformer failure and potential load shedding
    - Higher costs - demobilization & remobilization costs (c. $800k), labor inflation (4-5% p.a.)

2. Draft Resolution

The following resolutions are requested of the Board:

Approve the increase expenditure for RCTS transformer replacement from $59.5M to $101.6M; and

Note that the Project Scope has been expanded to include 2 x 220kV ROIs / earth switches on B1 and B2 Circuit Breaker circuits

Note that the scheduled in-service date remains November 2028

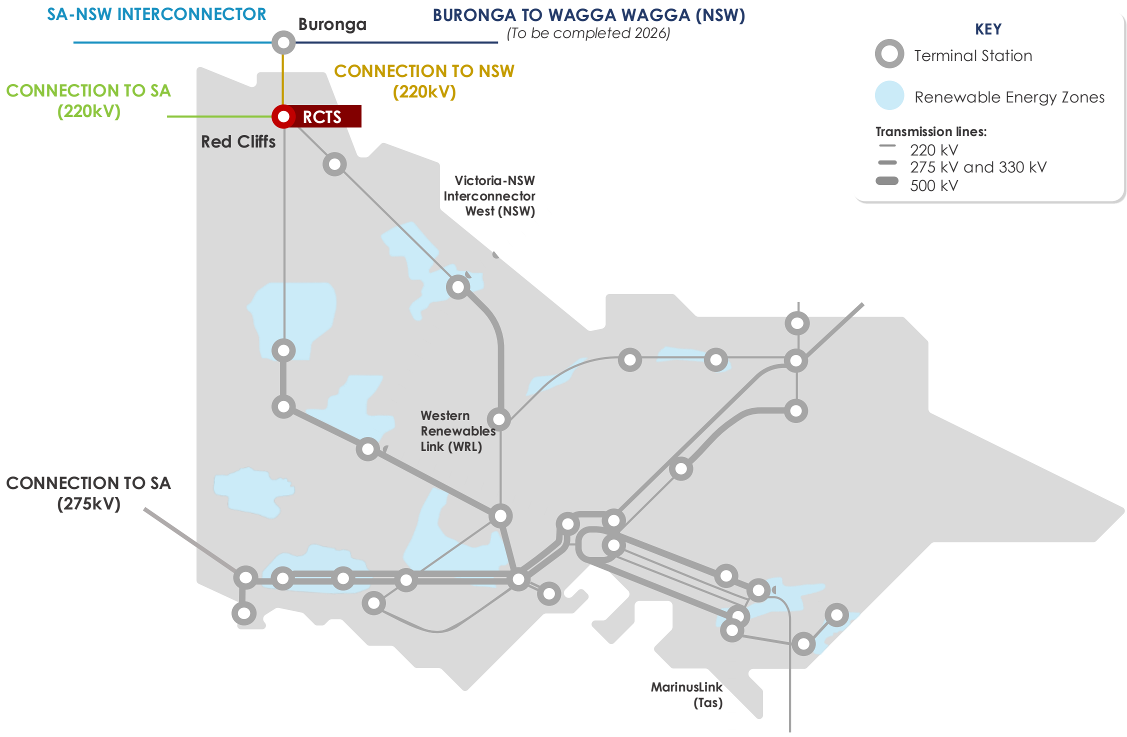
Note this project can be absorbed within our 5-year capex budget and current TRR period.

3. Station Background

Red Cliffs Terminal Station (RCTS) is owned and operated by AusNet Services and is in Red Cliffs, northern Victoria. Since it was commissioned in the early 1960's, RCTS served as the main 220/66 kV and 220/22 kV transmission connection point for distribution of electricity via the Powercor distribution network to communities in the towns of Red Cliffs, Colignan, Werrimull, Merbein, Mildura and Robinvale. Approximately 27,000 customers are supplied from RCTS, and 199 MW of large-scale solar generation is already connected at or downstream from RCTS.

RCTS will support increased inter-regional transfers via the upgraded Red Cliffs–Buronga 220 kV connection delivered under Project Energy Connect (SA–NSW interconnector with a connection to Victoria). It also plays an important role in integrating renewable generation in the Murray River REZ area.

Figure 2: Red Cliffs Terminal Station in the Victorian Transmission Network



4. Project Progress to Date

The project scope comprises of:

- Remove 4 x 220/66/22kV transformers and install 2x new B type transformers (150MVA, 220/66kV) and 2x new U type transformers (33MVA, 66/22kV).
- Demolish and replace existing transformer bays, augment and install new interplant switching circuits and associated protection and control schemes.

The project is in construction phase and was staged to ready the station for the delivery of the U transformers in April and May 2026 (stage 1A). The project is moving into stage 1B which utilises the 2026 outage season to commission the U transformers in September 2026. The remainder of the project scope falls within stage 2 (for further detail of scope split see the appendix). The timeline below assumes stages continue directly on from each other to maintain the project timelines (Asset in Service date of November 2028).

Figure 3: Project timeline

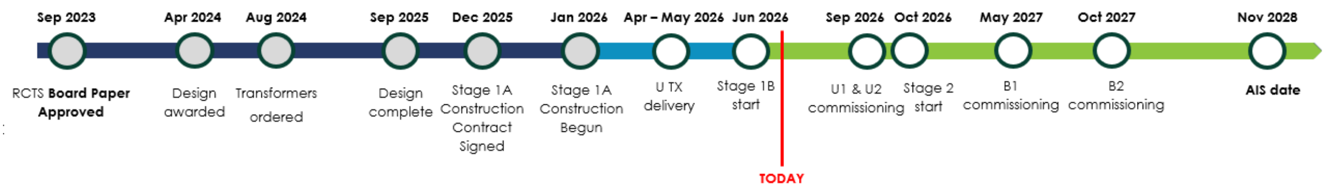


Figure 4: Project scope visual

5. Cost Changes

The cost increase has been assessed against an updated internal control estimate and the construction costs deemed fair and reasonable by an independent consultancy firm, E3. The contingency and management reserve values were updated after a P90 workshop in April 2026 and their values validated by an independent consultancy firm, E3.

The original Business Case expenditure was $59.5M. The Business Case was submitted and approved before design was issued as per AusNet's project approval processes. Since then, AusNet's project scoping and estimating capability has been strengthened through additional investment in Transmission Subject Matter Experts following the 2024 reorganization. Also, AusNet is gaining greater cost certainty by completing more activities e.g. early design work, before submitting a Business Case to improve Business Case submission cost and scope certainty.

The RCTS transformer project costs have increased to $101.6M. This is the cost to complete. The cost is a class 1 estimate with low escalation risk as materials are ordered, design completed, construction costs are contractor priced off the completed design, stage 1A is completed, stage 1B has begun and stage 2 has a fixed price offer from [C-I-C]. The reason for the $42.2M increase is broken down in the table below and waterfall chart in Executive Summary.

Table 1: Cost breakdown

Cost Type (Category)	Last Approved Budget ($ Nominal)	Revised Budget ($ Nominal)	Difference ($ Nominal)	Cause of Change
Design	$2,415,160	$2,698,344	$283,184	Additional design work for Bays A and G (locations of the additional scope). Some design overlooked in Business Case (BC) incl. OEM drawing reviews, revised protection systems, control room.
Internal Labor	$2,692,580	$3,825,099	$1,132,519	Higher-than-anticipated project, construction, commissioning, and stakeholder engagement effort.
Materials (free issued)	$19,518,926	$27,423,416	$7,904,490	Inflation for equipment between BC approval and ordering (transformers, primary, secondary panels relays, cables) contributes to $4.8M of delta. $2M additional materials for Bays A and G, control building modifications and DC supply upgrades not previously included. Rest is underestimation.
Plant & equip	$1,133,205	$15,751	-$1,117,454	Reallocated to contracts line.
Contracts	$25,106,642	$45,684,113	$20,577,471	Substation construction costs increased 55% since business case estimate as per AEMO inflation rates. $3M of risk transfer from AusNet contingency to [C-I-C] fixed price for latent conditions, weather, contaminated spoil. $1.1M plant & equip allocated to this line. $1.3M additional scope. $3.7M items missed in estimation incl. switching overheads, transformer installation, testing / commissioning supervision, more cable work.
Construction Insurance	-	$203,615	$203,615	Construction insurance previously part of the contract costs now is paid directly by AusNet.
Contingency	-	$5,489,791	$5,489,791	Business case only had Management Reserve not separate contingency. Contingency increased with project scope, and value to cover risks.
CFCs	$1,647,951	$3,835,974	$2,188,023	Additional capitalised finance charges required to service increased direct capital expenditure.
Overheads	$3,662,389	$4,297,685	$635,296	Additional overheads due to increased direct capital expenditure.
Mgmt. Reserve (MR)	$3,140,787	$8,001,382	$4,860,595	Increased with project scope, and value to cover risks.
Total capex	**$59,317,640**	**$101,475,170**	$42,157,530	
OPEX	0	0	0	N/A
Written down value	$167,554	$167,554	0	N/A
Total expenditure	**$59,485,194**	**$101,642,724**	$42,157,530	

Incremental Opex	Annual incremental Opex Impact ($'000)	Business Owner	Cost Centre
N	N/A	N/A	N/A

6. Risk

We can confirm the contingency and management reserve value is suitable for the cost to complete for RCTS.

- [C-I-C]
- A detailed risk analysis was undertaken where we reviewed for stage 1A, 1B and 2 AusNet's commercial position and considered the balance of risk in Terms & Conditions, the projects' special contract conditions, as well as project specific risks.
- We also completed a P90 workshop with all relevant parties in April 2026.
- A robust risk register was created with sensible likelihood and consequence levels. A Monte Carlo analysis was ran and completed, and we can confirm the contingency and management reserve values included are sufficient.

7. Needs Case

The needs case of the project was revalidated, and we can confirm there is still a strong need to replace the transformers.

The 4 power transformers at RCTS commissioned in the 1960s to 1980s are at advanced to extreme deterioration and must be replaced as part of this project to mitigate safety, explosion, fire and failure risk.

Main factors in why replacement is required:

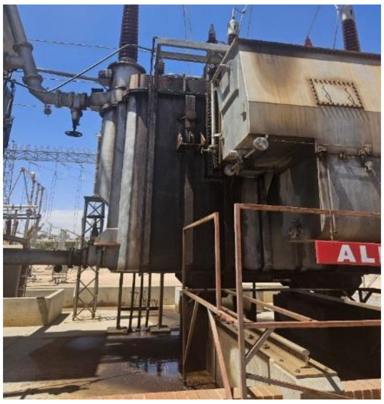
- 3 of these transformers (1A, 2A, 2B) have advanced ageing of core and windings, including cellulose degradation. The underling cellulose degradation is at end of life[1] and cannot be addressed through refurbishment
- 1 of the transformers (1B) has a high-risk short circuit withstand deficiency in design/construction, and short circuit levels are increasing due to Project Energy Connect and renewable connections. An identical unit failed in TTS in 2009 due to this issue. This issue cannot be managed through refurbishment

Additional factors that contribute to why replacement is required:

- The bushings are in a deteriorated state and present a significant risk of explosive failure and fire, requiring intervention in the short term. AusNet has insufficient spares of these vintage bushings to resolve this issue
- Onload tap changer problems often require transformers to be operated manually or taken out of service until repairs are made. Resolving these issues can cause long outages due to limited manufacturer support
- No Transformer Original Equipment Manufacturer - lack of knowledge and detailed internal information when considering refurbishment or investigating faults
- Ambient rating design too low (35°C-40°C) for current operating conditions (50°C) - reducing station capacity and with elevated operational risk
- AusNet presently maintains two spare 220/66 or 22 kV transformers, which must support a wide fleet of 97 units across both metropolitan and rural areas. Continuing to operate these transformers with the current asset risk is not strategic, especially considering the limited number of available spares.

Figure 5 and 6: 1A and 2B Transformer photos

[1] Degree of Polymerisation value ~250 at top of windings & ~350 at bottom of windings; CIGRE determines end-of-life DPv<250



8. Optioneering and Cost Benefit Analysis

Our updated optioneering and cost benefit analysis confirms that, despite the cost increases outlined, the project remains the most economically efficient option to maintain reliable and safe transmission network services at RCTS. The economic timing reveals the project should continue its current schedule.

We considered a long list of options and narrowed these down to a sub-set which we ran economic models on (further detail in table 2 and the appendix) and can confirm the preferred option remains Option 2, to continue to replace the 4 transformers by 2028 in line with current project scope and timing.

In summary:

- Deferring the project is not beneficial given the risks will be held for a longer duration, refurbishment in the meantime will only partially mitigate the asset failure risk and replacement will still be required shortly after refurbishment. Costs will rise over time.
- Descoping is not beneficial as the sequencing required at this site for transformer replacements means the U transformers need to be replaced first and they will be serviced through the B transformers. Therefore, the 22kV and 66 kV load will be supplied by the old B Tx, and a B transformer failure will thus impact both RCTS 22 kV and RCTS 66 kV load.
- Halting work after stage 1A construction is complete would result in none of the transformers being commissioned and therefore it is not a project option and not included in the table below. Halting work after stage 1B (commissioning the 2 U transformers) would align to option 4.

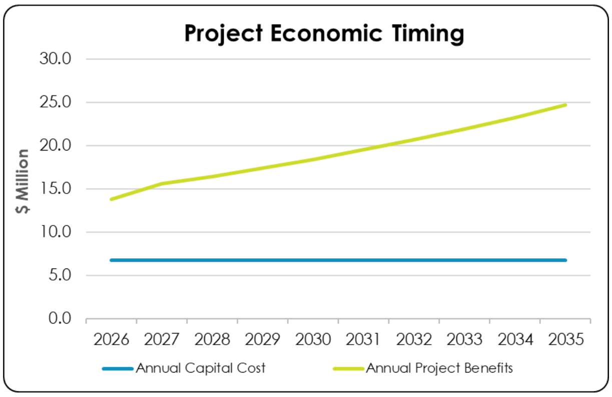
Table 2: Optioneering and cost benefit analysis

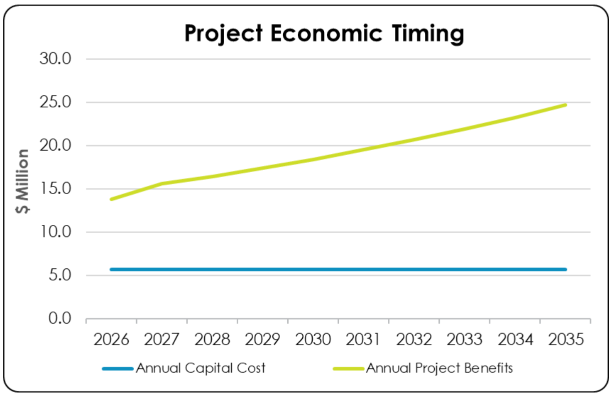
Option	Description	NPV and Comments
Option 1: Do nothing	Run to failure	$0 NPV, residual risk of $329M
Option 2: Replacement - Original Scope	Replace the 1A & 2A transformers (TX) with two new 33MVA 66/22kV (U) Tx in 2026. Replace the 1B & 2B Tx with two new 150MVA 220/66kV (B) Tx by 2028.	$216M NPV **PREFERRED OPTION**
Option 3: Life extension	Defer scope to 2033 and in interim (by 2028) refurbish	$151M NPV
Option 4: Refurbishment hybrid	Descope by replacing 1A & 2A with new Us in 2026 but remediate 1B & 2B in 2028	-$73M NPV
Option 5: Partial replacement	Descope by replacing 1A & 2A with new Us in 2026, replace 1B with new B, decommission 2B	$185M NPV
Modify operating conditions to meet needs case	Not viable - operating constraints (voltage control, fault-level limits) cannot be solved through operational changes	

Non-network new technology to solve the needs case	No viable non-network alternatives
Incorporate into augmentation	Not viable - no planned augmentation in the Victorian Transmission Plan, Transmission Connection Planning Report, or Victorian Annual Planning Report
Defer replacement of 1B and 2B by 1 year	Not viable - the new 33 MVA U transformers (and hence RCTS 22kV load) will be directly supplied by the B transformers. Deferring replacement of Bs by one-year exposes the RCTS 22kV and 66kV load to heightened supply risk during this period

The economic timing assessment has shown that this project (Option 2) is economic prior to 2026, supporting the proposed project in service date of 2028. Figures 7 and 8 below show the economic timing assessments for this option under both scenarios (Scenario 1 – NPV benefits if no work was done on project yet and Scenario 2 – NPV benefits as today, work already begun, considering sunk costs). The timing is very similar for both scenarios.

Figure 7 and 8: **Project Economic Timing (Scenario 1 LHS and Scenario 2 RHS)**





Continuing this project with the scope outlined in this paper (option 2) aligns with:

- Powercor, AEMO and VicGrid's network plans for the region as confirmed through discussions and joint planning sessions.
- Independent engineering consultancy firm E3's assessment of needs case and optioneering that concluded the full project scope is required and should continue to the project schedule. Their report is available at request.
- The RIT-T assessment. A regulatory investment test for transmission (RIT-T) has been completed for this project in September 2023. There is no formal requirement to redo a RIT-T for this project as there is no change to the preferred option, the project remains economic based on the revised cost, a non-network option is not feasible despite the increased project cost.

9. Financial Position

We can absorb the additional capex for RCTS in the Transmission 5-year plan, without deprioritising this project.

5-year plan

The current 5-year plan has a total $77.1M capex allocation for this project. The updated capex value (not including Management Reserve) of $93.5M is $16.4M above what was submitted for the project in the 5-year plan (see table below). This is driven by CY25/CY26. CY25 is now in the past and the Transmission line of business CY26 capex forecast is aligning to the capex budget for the year as of end of May 2026. Therefore, no prioritisation or descoping decisions need to be made to absorb RCTS increased capex.

Table 3: Summary of 5-yr plan vs updated capex forecast (nominal $)

	Previous	CY25	CY26	CY27	CY28	Total
5-year plan RCTS		4.8	13.6	37.4	21.4	77.1
Updated capex (incl contingency, not MR)	8.4	5.4	34.2	37.2	8.2	93.5
Delta between 5 yr plan and capex incl. contingency but not MR	N/A	**(0.6)**	**(20.6)**	**0.2**	**13.2**	**(16.4)**

TRR

- The project covers two regulatory periods RY23-RY27 (current period), and RY28-RY32 (next period)
  - In the current period, RCTS allowance is $27M compared to c. $60M (nominal excl. CFCs, and mgmt. reserve)[2] the project expects to spend.
  - However, overspends are assessed at the portfolio not project level with CESS[3] penalties applied to overspends as a revenue adjustment at portfolio level.
  - For next TRR period (RY28-RY32) RCTS forecast can be updated to reflect updated forecast over this time.
- All actual RCTS costs incurred will be reflected in Transmission RAB, allowing us to earn a return on that capital, and the full return of our capital (via depreciation) at the project level.

10. Recommendation

It is therefore recommended to approve the increase to the Project Budget for RCTS transformer replacement from $59.5M to $101.6M; and the additional Project Scope to include 2 x 220kV ROIs / earth switches on B1 and B2 Circuit Breaker circuits.

Note that the scheduled in-service date remains November 2028.

Following approval of this Board Paper we will be able to continue the project to complete the remainder of the project scope, and realize

[2] Allowances are approved in real dollars excluding CFCs; this conversion to nominal dollars is provided for reference only, and has been done using inflation consistent with the Roll Forward Model submitted with the TRR in October 2025

[3] Capital Expenditure Sharing Scheme – this incentive rewards/penalizes networks for 30% of underspends/overspends. For example, an overspend of $100M would result in a penalty of around $30M (subject to some other adjustments for timing of expenditure). The CESS is applied at a portfolio level, not for individual projects – overspend for a particular project may be offset by underspend on others

11. Appendix

Appendix A – Scope Breakdown

Scope

Retirement of 220/66/22kV transformers 1A, 1B, 2A and 2B transformers.

Installation of two new B type transformers (150MVA, 220/66kV) and two new U Type transformers (33MVA, 66/22kV) to replace the retired transformers.

Demolition and replacement of existing 1A, 1B, 2A and 2B transformer bays (firewalls, environmental bunding, rack structures etc.), augmentation and installation of new interplant switching circuits and associated protection and control schemes.

Project stages

- **Stage 1A** – station ready for the delivery of the two U transformers being delivered in April and May 2026
    - Civil and construction works to enable installation of U1 and U2
    - Install U1 and U2 transformers, new 220 kV, 66 kV and 22 kV switch bays
    - Lay 66kV and 22kV cables
- **Stage 1B –** U transformers are commissioned
    - Connect and commission new 220 kV, 66 kV and 22 kV switch-bays to their respective buses
    - Commission U transformers
    - Cutover 22kV supply from 1A transformer to U1 transformer
    - Cutover 1B transformer to temporary switch-bays
    - Decommission 1A transformer
- **Stage 2** – covers the remainder of the scope
    - Remove 1A transformer
    - Install and commission B1 transformer
    - Remove 2A and 2B transformers
    - Install and commission B2 transformer
    - Remove 1B transformer

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Appendix B - Options Analysis

A 2-part options analysis methodology was used. Part A considered options, assessed against investment need and technical feasibility criteria, part B considered 5 options, assessed for economic NPV benefits. The original business case scope (option 2) was the only credible and prudent path forwards.

Scenario 1 – NPV benefits if no work was done on project yet

Scenario 2 – NPV benefits as today, work already begun, considering sunk costs

The table below represents the options taken through to part B (detailed optioneering).

	Option 1 **Do nothing – run to failure**	Option 2 **Like for like replacement** (original scope) (Replace 1A, 2A, 1B & 2B with new U & B type TXs by 2028)	Option 3 **Life extension** (defer replacement until 2033 + interim remediation by 2028 of 1A, 2A, 1B & 2B	Option 4 **Refurbishment hybrid** (replace 1A & 2A with new Us in 2026, remediate 1B & 2B in 2028)	Option 5 **Partial replacement** (replace 1A & 2A with new U, replace 1B with new B, decommission 2B)
Economic Value (NPV of Economic Benefits)	**$0** Present Value of Baseline Risk: $329M	**$216M** Scenario 1 **$227M** Scenario 2	**$151M** Scenario 1 **$130M** Scenario 2	**-$73M** Scenario 1 **-$75M** Scenario 2	**$185M** Scenario 1 **$174M** Scenario 2
Impact on Supply Risk	**High** Assets remain in poor condition and present a material asset failure risk	**Low** Asset failure risk significantly reduced	**Medium-High** Assets remain in poor condition for five more years with increasing failure rates. Remediation does not resolve transformer core & winding issues.	**High** New U transformers are directly supplied by the aging 1B, 2B and B3 transformers, with short circuit withstand deficiency and high risk of dielectric failure.	**High** New U transformers are directly supplied by the new B and existing B3 transformers. Combined 66kV and 22kV capacity and redundancy impacted by decommissioning 2B.
Deliverability Impacts	**N/A** Does not deliver a solution to meet identified need	**Low** Aligned to brownfield staging; leverages mobilised team & procured equipment	**Medium** Deferral of scope leads to cost increases and need to store transformers. Long term rework likely to replace transformers as remediation of core & windings not feasible.	**Medium** Long term rework likely to replace 1B and 2B transformers as remediation of core & windings not feasible.	**Medium** Aligned to brownfield staging but need to either store or redeploy one B Type transformer.
Joint Planning Commitment Met	**No** Does not meet joint planning obligations and scope agreed by Powercor and included in VicGrid planning reports	**Yes** Scope agreed on by Powercor through joint planning and included in VicGrid planning reports	**No** Does not align with scope agreed on by Powercor and included in VicGrid planning reports	**No** Does not align with scope agreed on by Powercor and included in VicGrid planning reports	**No** Does not align with scope agreed on by Powercor and included in VicGrid planning reports
Outcome	**Not credible**	**Preferred Option** Only credible and prudent option. Delivers highest net benefit	**Not Recommended** Sustained exposure to material asset failure risk due to remediation not resolving transformer core and winding condition related issues.	**Not Recommended** Sustained exposure to material 1B & 2B transformer failure risk. Deviation from agreed functional requirement and joint planning outcome for RCTS.	**Not Recommended** Reduced 66kV and 22kV capacity. Deviation from agreed functional requirement and joint planning outcome for RCTS.

Notes: Scenario 2 has higher NPV for option 2 as lower CAPEX required to complete option when considering sunk costs in the CBA. The rest of the options have a lower NPV for scenario 2 vs scenario 1 due to additional CAPEX costs needed for temporary storage and inspection of the procured transformers if replacement is deferred or descoped.

Appendix C – Financial Breakdown

Project Expenditure for Approval

Project Expenditure for approval (nominal)	Prior Years	Calendar year (first 5 years) 2026	2027	2028	2029	2030	PCR Total
Baseline - Capex spend to date	13.9	2.1	-	-	-	-	16.0
Baseline - Capex delivery budget remaining	-	19.1	14.8	6.4	-	-	40.2
Additional Direct Capital	-	12.14	21.05	1.28	-	-	34.5
Additional Overheads	-	0.1	0.6	(0.1)	-	-	0.6
Additional Capitalised Finance Charges	-	0.8	0.8	0.6	-	-	2.2
Project Delivery Budget (SAP Capex budget)	**13.9**	**34.2**	**37.2**	**8.2**	**-**	**-**	93.5
Baseline - Management Reserve	-	0.4	0.8	1.9	-	-	3.1
Additional Management Reserve	-	-	-	4.9	-	-	4.9
Utilized Management Reserve	-	-	-	-	-	-	-
Management Reserve	**-**	**0.4**	**0.8**	**6.8**	**-**	**-**	8.0
Total Capex for Approval (incl risk, CFCs & OHs)	**13.9**	**34.6**	**38.1**	**14.9**	**-**	**-**	**101.5**
Baseline - Project Opex spend to date	-	-	-	-	-	-	-
Baseline - Project Opex delivery budget remaining	-	-	-	-	-	-	-
Additional Project Opex	-	-	-	-	-	-	-
Total Project Opex for Approval	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Written down value of assets retired/sold	-	0.2	-	-	-	-	**0.2**
Total New Estimated Expenditure for Approval (nominal)	**13.9**	**34.8**	**38.1**	**14.9**	**-**	**-**	**101.6**

Change Breakdown Analysis

Note the table below does not include Management Reserve

Changes to Approved Delivery Budget	CAPEX	PROPEX	TOTEX
Business Case Baseline (BC delivery budget, Incl CFCs & OHs)	56.2	-	56.2
Current Approved Baseline (Including all PCRs to date)	56.2	-	56.2
Requested Change (Additional budget requested in this PCR Incl. CFCs & OHs)	37.3	-	37.3
New Baseline (Delivery Budget post-change incl. CFCs & OHs)	**93.5**	**-**	**93.5**

Changes to Approved Management Reserve	
Original Approved Management Reserve (BC)	3.1
Current Approved Management Reserve	3.1
Additional Management Reserve Requested	4.9
Less Management Reserve to be utilised	-
New Total Management Reserve	**8.0**