TD-0007404 ERTS Redevelopment - Stage 2 Business Case (BC)

Portfolio Business Line:		Work Category:	Work Code / Name:
Transmission		Replacement	2002 TCAPEX Station rebuilds
Project Start date:		**Commissioning Readiness Date:**	**Project Completion Date:**
14/01/20		31/10/24	31/01/25
Delivery Budget ($):		**Management Reserve ($):**	**Total Estimated Expenditure for Approval ($):**
Capex ($)	$23.1 M	$0.6 M	$24 M
Opex ($)			
Is this budgeted in the current Portfolio FY Plan?			**Incremental change in Opex**
Yes. $ 0.8 M in FY21 (FY22 - $1.3M, FY23 - $7.2M, FY24 - $11.5M, FY25 – 3.9M)			N/A

Executive Summary:

This business case seeks approval to invest $23.6 M (including overheads, contingency allowance and finance charges, but excluding $0.3 M write downs) to replace two power transformers, eight 66 kV circuit breakers and associated primary and secondary assets that are in poor condition and cause supply reliability, safety, environmental and operational issues at East Rowville Terminal Station (ERTS) in an integrated project.

The regulatory investment test (RIT-T) has been completed for this project with the publication of the Project Assessment Conclusions Report (PACR) on 17 November 2020. No non-network proposals were received during the RIT-T consultation and a network solution was selected as the preferred solution to address the emerging asset failure risk at ERTS.

The first of two stages to replace assets that present a failure risk at ERTS is nearing completion. The first stage (Project TD-0003440) replaced the B3 transformer and five 66 kV circuit breakers.

This business case (second stage) includes replacement of two 150 MVA 220/66 kV transformers and eight 66 kV circuit breakers with associated primary and secondary assets. The project will improve the reliability of supply and reduce the safety risk associated with an unlikely asset explosive failure at ERTS; consistent with the regulatory obligation to maintain the quality, reliability and security of supply of prescribed transmission services as stated in the National Electricity Rules. The project is planned to be completed by January 2025.

This project will not have STPIS penalties for planned outages.

Project Initiator & Dept.	Prepared by:	Date BC submitted:
Transmission Network Planning		09/03/21

Business Case e-sign-off

Key Project Details	
Project # / Title / Version	TD-0007404 ERTS Redevelopment Stage 2
Revision (Y/N)	N
Endorsement:	
Name: Title: Manager, Transmission Network Planning	Name: Title: Manager, Major Projects
Signature: **Endorsed via email**	Signature: **Endorsed via email**
Date: 10/02/2021	Date: 10/03/2021
Comments:	Comments: Note: to advise that the FY22 budget allowance required will now be $1.9M.
Name: Title: GM Network Strategy & Planning	Name: Title: GM Finance – Networks & Technology
Signature: **Endorsed via email**	Signature: **Endorsed via email**
Date: 08/02/2021	Date: 09/03/2021
Comments:	Comments: - BC capex of $23.6M is slightly lower than the RIT-T capex of $24.1M as some asset replacements were removed from the scope. This change does not require a revision of the RIT-T as it is still in the estimate accuracy band. - Recommend a health check of the project mid-flight to review how risks are being managed.
Approvals:	
Name: Title: EGM, Network Management	Name: Title: CFO / IC Chair
Signature: **Endorsed via Investment Committee**	Signature:
Date: 12/03/2021	Date: Mar 19, 2021
Comments:	Comments:
Name: Title: Managing Director	
Signature:	
Date: Mar 19, 2021	
Comments:	

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Business Case Accountability Matrix

The table below provides delineation and shows *who* is responsible to review *which* section of the BC. This will expedite approval as only the person best placed to review a specific section will be accountable for it.

When the business case is approved, all the stakeholders below will be copied into the confirmation email.

Name	Role	Section Developed	Section Reviewed	Reviewed / Endorsed
	Project Initiator	All aspects of the Business Case		20/10/20
	Project Sponsor/Owner		Executive summary Project Background Scope Schedule Options considered (economic & technical) Risk assessment Benefit assessment	31/11/20
	Benefit Owner/s		Financial assessment Options considered Benefit assessment	20/10/20

1. FINANCIAL SUMMARY

Transmission Regulatory Key	PS

Table 1.1: Project Expenditure Forecast

Project Expenditure for approval (nominal)	First 5 years					Lifecycle Total
	2022	2023	2024	2025	2026	
Direct Capital expenditure	1,354.1	6,626.0	10,339.3	3,059.7	-	21,379.1
Overheads	56.6	277.0	432.2	127.9	-	893.6
Capitalised Finance Charges	30.9	220.2	232.5	343.9	-	827.5
Project Delivery Budget (SAP Capex budget)	**1,441.6**	**7,123.2**	**11,003.9**	**3,531.5**	-	23,100.2
Management Reserve	-	-	-	548.6	-	548.6
Total CAPEX for Approval (incl risk, CFCs & OHs)	**1,441.6**	**7,123.2**	**11,003.9**	**4,080.1**	-	23,648.8
Operating Expenditure for approval (Project Opex)	-	-	-	-	-	-
Written down value of assets retired/sold	-	-	295.0	-	-	295.0
Total Estimated expenditure for approval (nominal)	**1,441.6**	**7,123.2**	**11,298.9**	**4,080.1**	-	**23,943.8**

Table 1.2: Net Present Value of Cashflows (Financial Analysis)

WACC Reference date Mar-20

Investment Option	NPV of cashflows	IRR	Payback period (yrs)
BAU	-	-	-
Option 1	2,962.0	4.4%	38
Option 2	1,542.0	4.5%	38

Table 2.3: Analysis of investment options

Analysis of investment options ($'000 - Present Value)	Capex	Opex	Total Financial Costs	Potential Costs	Other Economic Costs & (Benefits)	Total PV Cost	PV Cost Ratio (compared to BAU)
BAU	-	116.2	116.2	-	50,974.8	51,091.0	1.00
Option 1	20,899.7	36.0	20,935.7	-	7,967.6	**28,903.3**	**0.57**
Option 2	10,675.8	36.0	10,711.7	-	22,814.3	33,526.0	0.66

2. PROJECT BACKGROUND

East Rowville Terminal Station (ERTS) was commissioned in the 1960's. ERTS is the main transmission connection point for distribution of electricity to communities in south-eastern metropolitan Melbourne – from Scoresby to Lyndhurst and Belgrave to Mulgrave, via two electricity distribution companies United Energy and AusNet Services. Approximately 128,000 customers depend on ERTS for their electricity supply. While 92% of these customers are residential, more than 50% of energy supplied by ERTS is consumed by commercial customers – equivalent to 825 GWh per year.

Peak demand at ERTS occurs during summer periods. The highest peak demand of 504.9 MW was recorded in the summer of 2008/09 during an extreme weather event. The annual peak demand has not reached that level since 2008/09. The peak demand was 463.3 MW during the summer of 2019/20. The reduction compared to the 2008/09 peak demand is partly due to transfer of electricity demand from ERTS to other terminal stations. The Australian Energy Market Operator (AEMO) forecasts that the peak demand at ERTS will remain at the current level over the next ten-year period.

Several primary (power transformers, circuit breakers, instrument transformers, earth switches, isolators etc.) and associated secondary (protection and control) assets at ERTS are in poor condition and present a material failure risk.

Asset Condition Drivers

AusNet Services classifies asset conditions using scores that range from C1 (initial service condition) to C5 (very poor condition). The asset condition assessment for ERTS was conducted in 2019 and reveals that most assets at the terminal station are in poor condition (C4) or very poor condition (C5). For the selected assets, the probability of failure is high, and is likely to increase further if not replaced. Table below provides a summary of the condition of relevant major equipment.

Summary of major equipment condition scores to be replaced under this project (Stage 2)

Asset class	Condition scores				
	C1	C2	C3	C4	C5
Power transformers				2	
66 kV circuit breakers[1]				2	6
66 kV instrument transformers				3	

Power Transformers

There are four 150 MVA 220/66 kV transformers at ERTS. The 'B1' and 'B4' transformers were commissioned during the late 1960's and a design issue has been found with this type of transformers, which could result in a major transformer failure for close in network faults. The transformers have deteriorated significantly and according to the 2019 asset condition assessment report both transformers are in poor condition (C4). Assets in this condition (C4) require remedial action within the next two to ten years.

An investigation of a failure of a similar transformer in AusNet Services network in March 2016 revealed that the failure was as a result of previous buckling of the 66 kV windings.

66 kV Circuit Breakers

Seven of eight 66 kV circuit breakers selected to be replaced are bulk-oil circuit breakers that have provided more than 50 years of service. These bulk-oil circuit breakers are amongst the oldest circuit breakers installed in the

[1] Four 66 kV circuit breakers in C4/C5 condition (B1, B3 and B4 Transformer CBs in C4 condition and No 1B capacitor bank CB in C5 condition) are to be managed through refurbishment and hence not included for replacement

network and are critical for the secure supply of 66 kV load at ERTS. A summary of the key issues of these type of circuit breakers include:

- Age/duty related deterioration including the erosion of arc control devices, bushing oil leakages, and wear of operating mechanisms and drive systems;
- Limited fault level capability requiring restrictive switching configurations;
- Maintenance intensive;
- Manufacturer no-longer provides technical support or spares;
- Insufficient oil bunding.

The other 66 kV circuit breaker selected to replace is live tank SF6 capacitor bank circuit breaker that has provided 37 years of service. Due to higher switching duty capacitor bank circuit breakers deteriorate faster and have a shorter service life. This circuit breaker has performed more than 2750 switching operations. The circuit breaker has a design limitation of 2000 operations when used for back-to-back capacitor switching, thus is exceeding design life by 750 operations. During past 5 years there were a higher than normal amount of notifications for this circuit breaker.

66 kV Instrument Transformers

Three 66 kV capacitor bank current transformers in poor condition (C4) are selected to be replaced. All three current transformers have provided over 45 years of service. These current transformers demonstrate age related deterioration. There were some recent failures of this type of current transformers. In an explosive failure, porcelain projectiles could cause collateral damages to the adjacent plants and pose safety risks.

Secondary Assets

Unlike primary assets, secondary assets become obsolete within a typical time frame of 15 years when they are no longer supported by manufacturers, are technically incompatible with interfacing equipment or are no longer able to provide the functionality required to comply with industry standards or regulation. The condition of a secondary asset is assessed based on its capacity to deliver its designed function. The selected secondary assets for replacement have been based on the above criteria and the asset management strategy (AMS10-68).

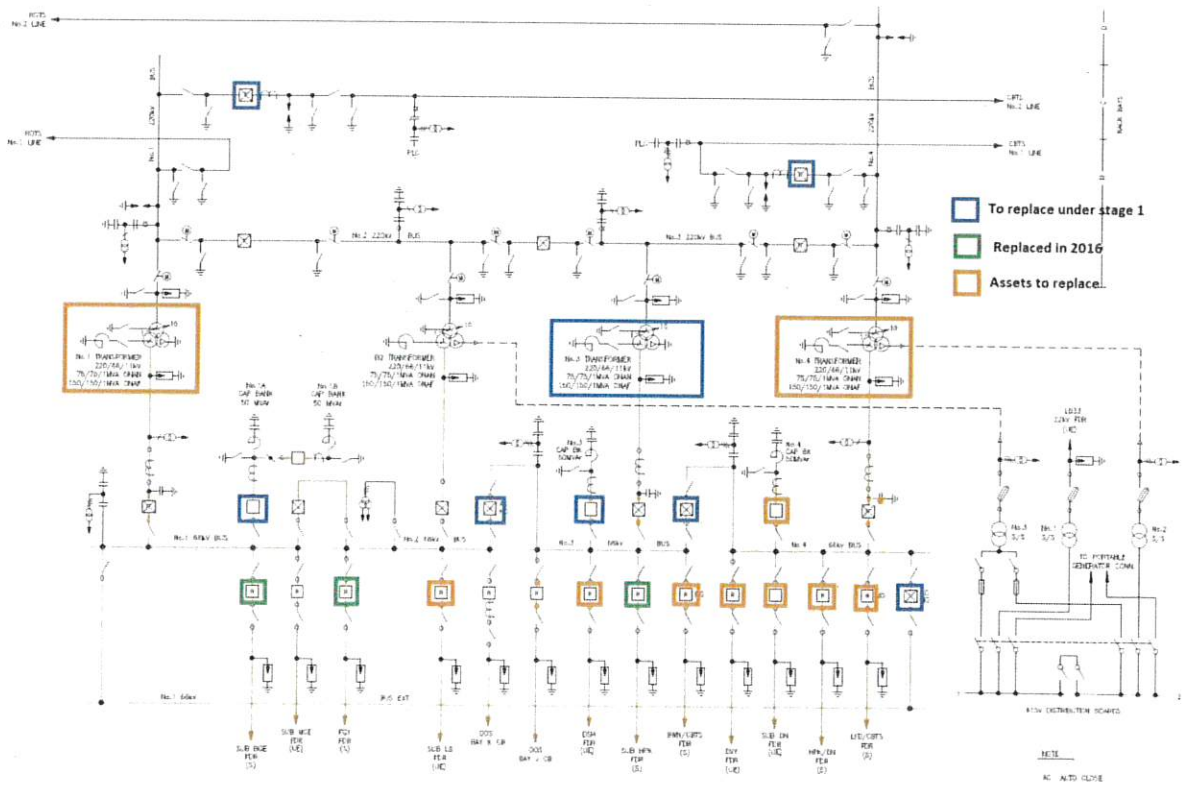
The secondary scope includes interface work of existing transformer protection schemes with the new transformers. Most of the electro-mechanical relays of 66 kV feeder protection, bus protection and capacitor bank protection schemes are selected for replacement. Electro-mechanical relays are single function relays with mechanical measurement registers, rotating disc mechanisms, mechanical bearings and spring-based energy storage. Electro-mechanical relays represent the oldest relay technology. These relays are obsolete with no manufacturer support. Their limited capability and functionality restrict implementation of current standards. The EDMI Mk3 revenue meters (in poor condition) are no longer supported by the manufacturers.

More details of selected asset to replaced are provided in appendix A5.

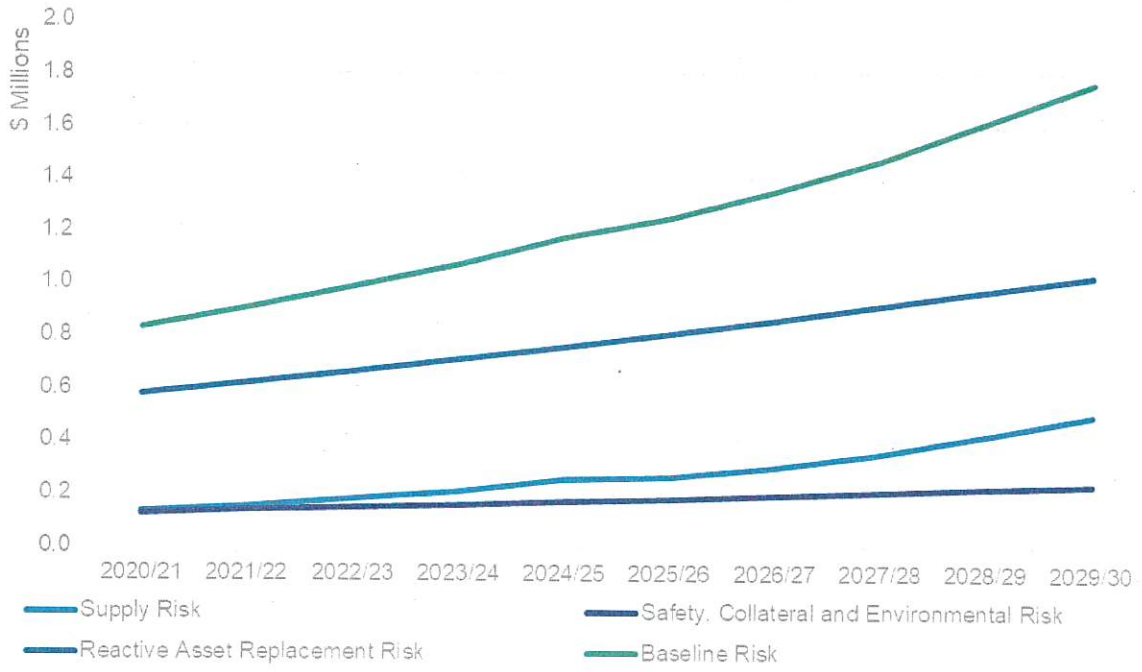
The emerging service constraints at ERTS are:

- Health and safety risks presented by a possible explosive failure of 66 kV instrument transformers, 66 kV bulk oil circuit breaker bushings and 220/66 kV transformer bushings;
- Security of supply risks presented by a failure of the Toshiba 220/66 kV transformers or 66 kV circuit breakers;
- Collateral plant damage risks presented by an explosive failure of a transformer bushing, instrument transformer or bulk oil circuit breaker bushing; and
- Environmental risks associated with insulating oil spill or fire.

The B3 transformer was replaced in September 2019 under the Stage 1 project (TD-0003440). The B2 transformer that was installed in 2011 is still in good condition. Apart from the B3 transformer, five 66 kV circuit breakers (including three bulk oil and two minimum oil circuit breakers) were also replaced under Stage 1 as shown below (marked in blue).



Assets marked in orange are planned to be replaced with this project (Stage 2). The present value of the baseline risk costs is calculated to be $23 million over the forty-five year period from 2020/21. The key elements of the risk costs are shown below.



The majority of the primary and secondary assets will be in good condition after completion of Stage 2 in early 2025.

3. SCOPE – HIGH LEVEL

The following is a brief summary of the scope of work for the preferred option (Integrated Replacement) to address the identified risks at ERTS:

- Replace the B1 and B4 220/66 kV transformers in situ with the same size (150 MVA)
- Replace seven 66 kV bulk oil circuit breakers with 66 kV dead tack circuit breakers
- Replace a 66 kV capacitor bank circuit breaker with a 66 kV live tank circuit breaker
- Replace three 66 kV capacitor bank balance current transformers
- Interface works of existing transformer protection schemes with the new primary equipment
- Replace selected 220 kV line protection
- Replace selected 66 kV feeder protection, bus protection and capacitor bank protection
- Interfacing SCADA with new equipment
- Replace selected energy meters

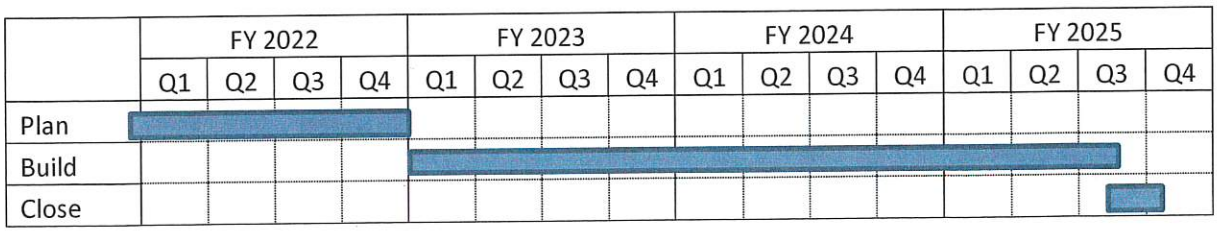
A detailed scope of work is attached in Appendix A1.

3.1 Standards to be developed for this project

The engineering standards for this project are current and available via ECM and no new standards are required for this project.

4. SCHEDULE

Key Milestone	Date
Stage Gate 2 Approval	14/01/20
Control Estimate Complete	30/06/22
Commissioning Readiness Complete (Should be in SAP)	31/10/24
Project Completion / Regulatory Commencement	31/01/25



5. OPTIONS CONSIDERED

The following options have been considered and assessed over 45 years from FY21.

Option	Description Summary
BAU	Business as Usual
1	Integrated Replacement
2	B1 and B4 Transformer Replacement

5.1 Business as usual

The Business as Usual (BAU) option quantifies the base line risk (primarily supply and financial risk) at ERTS. It is used for modelling purposes in the economic cost-benefit analysis to determine the economical time for the asset replacement option with the lowest PV cost to proceed. A failure of any of the deteriorated assets at ERTS (220/66 kV transformer, 66 kV circuit breaker or 66 kV instrument transformer) poses a material supply and safety risk.

The "Business as usual" option does not address the following AusNet Services obligations:

- under the National Electricity Rules to maintain the quality, reliability and security of supply of prescribed transmission services
- under the Electricity Safety Act to operate, maintain and decommission the supply network to minimise as far as practicable the hazards and risks to the safety of any person arising from the supply network

This option has a total present value (PV) cost of $51.1 M, which is mainly due to escalating supply and financial risks costs. The Business as Usual option is not an economical option or a prudent management strategy for the assets at ERTS.

Capex and Opex	No capex is included for this option. Opex consists of transformer and circuit breaker operation and maintenance costs, which is estimated at $5.1 K pa given the age and condition of the assets at ERTS.
Community Costs & Benefits	The community cost of the BAU option includes safety, supply, collateral, financial and environmental risk cost as well as transformer losses. The monetised risk has been calculated in accordance with AMS 10-24 and the following input assumptions: • Safety consequence = $0.044 M (weighted with the likelihood of consequence) • Plant Collateral Damage Cost = $1 M • Environmental Risk Cost = $0.1 M • Supply risk cost – the N-1 risk cost is insignificant while the N-2 risk cost is substantial. The supply risk cost is evaluated using the Value of Customer Reliability (VCR) of $34.245 / kWh for ERTS • Transformer losses – includes load losses based on the forecast demand at ERTS as well as no load losses using the following assumptions for losses on the two old transformers.

	Old	New
No load losses (kW)	95	50
Load losses @ 150 MVA (kW)	776	475

- The annual risk cost and operating cost of the deteriorated switchgear at ERTS increases from $1.2 M to $2.5 M over the period from FY21 to FY32. (See detailed breakdown for each voltage in the table below).

Business as Usual	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Annual payment for Non-Network Options	0	0	0	0	0	0	0	0	0	0	0	0
RISK AND OPERATING COST												
Transformer Safety, Collateral, Enviromental and Reactive Asset replacement Risk	0.396	0.423	0.452	0.483	0.514	0.548	0.583	0.619	0.658	0.698	0.739	0.783
220 kV Circuit Breaker Risk Cost	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
220 kV Instrument Transformer Risk Cost	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
66 kV Circuit Breaker Risk Cost	0.238	0.258	0.281	0.304	0.330	0.354	0.381	0.411	0.443	0.476	0.512	0.550
66 kV Instrument Transformer Risk Cost	0.124	0.135	0.148	0.160	0.174	0.188	0.203	0.219	0.235	0.252	0.270	0.289
22 kV Circuit Breaker Risk Cost	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22 kV Instrument Transformer Risk Cost	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N-1 Transformer Supply Risk	0.015	0.018	0.024	0.025	0.033	0.021	0.021	0.022	0.024	0.025	0.026	0.028
N-2 Transformer Supply Risk	0.057	0.066	0.076	0.086	0.106	0.108	0.113	0.134	0.159	0.179	0.201	0.227
N-3 Tranformer Supply Risk	0.001	0.003	0.006	0.010	0.018	0.029	0.044	0.066	0.095	0.134	0.184	0.249
N-4 Tranformer Supply Risk	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transformer Maintenance	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Circuit Breaker Maintenance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transformer Losses	0.379	0.379	0.380	0.381	0.380	0.377	0.373	0.373	0.377	0.376	0.378	0.378
Annual Risk Cost and Operating Cost	1.215	1.288	1.371	1.457	1.560	1.630	1.729	1.849	1.995	2.145	2.314	2.506

5.2 Preferred option - Integrated Replacement

This option involves replacing the B1 and B4 Toshiba transformers as well as eight 66 kV switch bays with associated primary and secondary assets that are in poor condition in a single project.

This option addresses all the identified risks and has the lowest PV cost ($28.9 M) of all technically feasible options. It is also the preferred option as identified in the RIT-T. The project economic timing is prior to summer 2024/25.

Capex and Opex	The project capex cost is $23.1 M (excluding asset retirement cost and management reserve). The project will deliver a $3.6 k saving in Opex annually. The saving is due to the lower expected maintenance cost associated with the new transformer and switchgear.
Community Costs & Benefits **(Regulated projects)**	The residual safety, supply, collateral and environmental risk cost will be negligible after project completion as it addresses all the identified risks.
Incentive Benefits **(Electricity only)**	

5.3 Option 3 - B1 and B4 Transformer Replacement

This option involves replacement of the B1 and B4 transformers with associated primary and secondary assets that are in poor condition. This will address the identified risks posed by the poor condition transformers but not the risks posed by the 66 kV switchgear that are also in poor condition.

The total PV cost of this option ($33.5 M) is higher than the preferred option and it does not address all the identified risks. This option is not recommended.

Capex and Opex	

	The capex for this option is $12.8 M. Opex consists of transformer and circuit breaker operation and maintenance cost. The project will deliver a $3.6 k saving in Opex annually. The saving is due to the lower expected maintenance cost associated with the new transformers.
Community Costs & Benefits	The residual safety, supply, collateral and environmental risk cost will be low after project completion. This project would address some of the identified risks, but not all.
Incentive Benefits (Electricity only)	

6. BENEFIT ASSESSMENT

It is not necessary to identify benefits from each category – insert N/A where not applicable

Note: Productivity and Cost Avoidance are to be detailed in Non-financial benefits section

Financial Benefits

Financial Benefits are those that will have a direct bottom line (budget) impact on the profitability of AusNet Services (opex or propex or incentive, either on planned levels of expenditure and incentives, or growth (Revenue increase). Financial Benefits associated an increased Regulatory Asset Base are not considered appropriate benefits for a Regulated Business Case.

Note: Productivity and Cost Avoidance are to be detailed in Non-financial benefits (section 6.2)

8 Financial Benefits Summary							
Financial Benefit Category	**Details and Measure (baseline, metric, and target)**	**Benefit Start to Full Realisation Date**	**Capex**		**Opex**		**Business Benefit Owner** *Who stands to gain the most from the benefit? Must be role specific and cost centre provided*
			Labour	**Non-Labour**	**Labour**	**Non-Labour**	
1.Cost Efficiency – Reduction							
Recurring cost savings		Benefit start dd/mm/yyyy Full Realisation Date dd/mm/yyyy	$	$	$	$	Role: Cost centre:
One-off cost savings			$	$	$	$	
2. Growth (Revenue Increase)			**Capex**		**Opex**		
Recurring Revenue (incl. incentives)		Benefit start dd/mm/yyyy	$		$		Role: Cost centre:

		Full Realisation Date dd/mm/yyyy			
One-off Revenue			$	$	

Financial Benefits Summary (Definitions)		
Financial Benefit Item	**Definition**	**Example**
Labour	Reduced FTE – Reduced opex / capex	Decrease current asset maintenance costs
Non-Labour	Reduced material costs	Reduce working capital requirements
Recurring savings (Planned)	Improved cost-to-serve	Reduced costs – once off / sustainable Reduced energy losses
One-off savings (Planned)		
Recurring Revenue (incl. incentives)	Reduced debtor / creditor days Improved Net Working Capital position Improved collections / margins on customer contributions	Increased customer contributions Improved incentive payments
One-off Revenue		

Non-Financial Benefits

Non-Financial Benefits are those that will have a business benefit which will not directly impact the financials (cost centre / budget) of AusNet Services.

Every effort must be made to quantify these so they can be measured and tracked.

#	Benefit Category	Benefit Sub-Category	Benefit Name (& description)	Benefit Start to Full Realisation Date	Measure - Baseline, Metric and Target	Assumptions	Business Benefit Owner
	Duplicate benefits must be avoided in the Benefit Assessment.	*Use one of the existing categories below.*	*Provide a short benefit name and a description of what benefit is being provided by the program, project, or initiative.*	*When can benefits (i) start to be tracked (date after key milestone) and (ii) when will they be fully realised?*	*What is the baseline, metric used, and the result expected?*	*Provide the assumptions behind how the program, project or initiative will deliver the benefit.*	*Who stands to gain the most from the benefit? (e.g. Business Owner) Must be role specific*
3	**Future Ready Capabilities and Culture** *Benefits that enhance the capabilities or culture of AusNet Services to make the organisation a more enjoyable and desirable place to work*	Productivity		Benefit start dd/mm/yyyy Full Realisation Date dd/mm/yyyy			
		People and Culture		Benefit start dd/mm/yyyy Full Realisation Date dd/mm/yyyy			
4	**Compliance** *Benefits to meet compliance against a specific reg \ legal obligation*	Regulatory & Legal	Environmental benefits (by removing risks) NER obligations (to maintain the quality, reliability and security of supply) ESA obligations	Benefit start 15/09/2022 Full Realisation Date 31/10/2024	Avoiding possible environmental damage due oil spills Comply with NER and ESA obligations		
5	**Customer Centricity** *Benefits that provide direct improvement of our*	Customer – General	Reliable power supply to customers	Benefit start 15/09/2022	Customer satisfaction		

#	Benefit Category	Benefit Sub-Category	Benefit Name (& description)	Benefit Start to Full Realisation Date	Measure - Baseline, Metric and Target	Assumptions	Business Benefit Owner
	services to customers or enhance AusNet Services' reputation within the community			Full Realisation Date 31/10/2024			
6	**Risk Management** *Benefits that reduce the risk of either a poor outcome associated with one (or more) of the other benefit categories or a risk of future cost increase.*	Risk Controls	Security of supply	Benefit start 15/09/2022 Full Realisation Date 31/10/2024	SAIDI		
		Cost Avoidance	Possible STPIS incentive – due to one or more transformer unplanned outages Opex saving	Benefit start 15/09/2022 Full Realisation Date 31/10/2024	STPIS loss of supply event as a result of any unplanned transformer or CB outage could incur STPIS service component penalty Annual Opex saving of $3.6k	Possibility of failing one or both transformers before planned replacement	
7	**Mission Zero** *Benefits that provide a safer working environment for staff, our customers, and the community*	Safety – General	Safe working environment to the employees.	Benefit start 15/09/2022 Full Realisation Date 31/10/2024	Safer work environment		–

7. RISK ASSESSMENT

7.1 Project delivery risk (known)

Project Risk	What could occur?	Consequence *Rating 1-5**	Likelihood *Rating (Almost Certain ~ Rare) **	Current Risk Rating *Rating A-E**	Actions and controls in place to manage/reduce risk	Target Risk Level *A-E**
Plant explosive failure during project delivery phase	Safety risk and supply outages	4	Unlikely	C	Monitor assets during project. Safety review completed prior to project start.	D
Plant failure during project delivery phase	Supply outages	2	Possible	D	Contingency plans, load transfers and monitor assets for any deterioration in condition.	E
Brown Field Redevelopment	Supply outages	2	Possible	D	Manage outages and limit it to the lower demand period.	E

Refer to the Risk Assessment Criteria document on the Risk Management SharePoint site on the Loop: Link

Has a Costed Risk Workshop been conducted to calculate Management Reserve for this project?	☐ Yes	☒ No

7.2 Other risks

No other known risk at this stage.

8. HIGH LEVEL CHANGE IMPACTS

8.1 High Level Impacts

Considering a BAU asset installation project, this project is not expected to change the system, processes, people or culture. Accordingly, change impact is none or minimal.

Attach the completed Rapid Change Impact Assessment here.

RAPID CHANGE IMPACT ASSESSMEN

8.2 Stakeholder Groups impacted by the change(s)

Not applicable

9. PROJECT GOVERNANCE

1. AusNet Services Portfolio Framework for governance on capital investments applies.
2. CMA mandatory requirements will be followed including monthly forecasting, monthly status reports (updates on scope, cost, and time), stage gates, and change control request process.
3. Establishment of a Project Reference Group or Steering Committee comprising key strategic and operational representatives to oversee the project and provide:
    - Oversight of project status
    - Guidance and direction
    - Review and endorsement for project key deliverables/decisions
    - Dissemination of information to other relevant parties
    - Facilitate the Transition to Support Process
4. Escalation Process for resolution of risks and issues.

10. FINANCIAL ASSESSMENT

Capex profit centre	13260
Propex profit centre	
Opex (BAU) owner & cost centre	

10.1 Capex Breakdown

Capex Breakdown (incl mngt reserve - nominal)	First 5 years					Lifecycle Total
	2022	2023	2024	2025	2026	
Design	1,092.5	1,114.4	119.6	-	-	2,326.5
Internal Labour	261.6	420.5	584.9	272.4	-	1,539.4
Materials	-	2,513.5	5,127.5	871.7	-	8,512.6
Plant & Equipment	-	189.4	331.2	140.8	-	661.4
Contracts	-	2,095.3	3,663.8	1,557.1	-	7,316.3
Meter Costs	-	-	-	-	-	-
Risk	-	292.9	512.2	217.7	-	1,022.8
Other	-	-	-	-	-	-
Management Reserve	-	-	-	548.6	-	548.6
Total Capex	1,354.1	6,626.0	10,339.3	3,608.3	-	21,927.7

10.2 Opex Breakdown

Opex excl Project implementation (nominal)	First 5 years					Lifecycle Total
	2022	2023	2024	2025	2026	
BAU Total Opex	-	-	5.3	5.4	5.5	368.8
Incremental Opex Costs - Option 1	-	-	-	-	-	-
Opex Savings - Option 1	-	-	(3.7)	(3.8)	(3.9)	(242.9)
Net Budget impact (split by division below)	-	-	(3.7)	(3.8)	(3.9)	(242.9)
New Cost profile	-	-	**1.6**	**1.6**	**1.6**	**125.8**

10.3 Division Budget Impact

Budget impact by division (nominal)	First 5 years					Lifecycle Total
	2022	2023	2024	2025	2026	
RES	-	-	(3.7)	(3.8)	(3.9)	(242.9)
Ops&Services	-	-	-	-	-	-
Mondo	-	-	-	-	-	-
Finance	-	-	-	-	-	-
Technology	-	-	-	-	-	-
Strategy & Transformation	-	-	-	-	-	-
People, Safety & Customer	-	-	-	-	-	-
Governance	-	-	-	-	-	-
Managing Director	-	-	-	-	-	-
Total Budget impact: Option 1	-	-	(3.7)	(3.8)	(3.9)	(242.9)

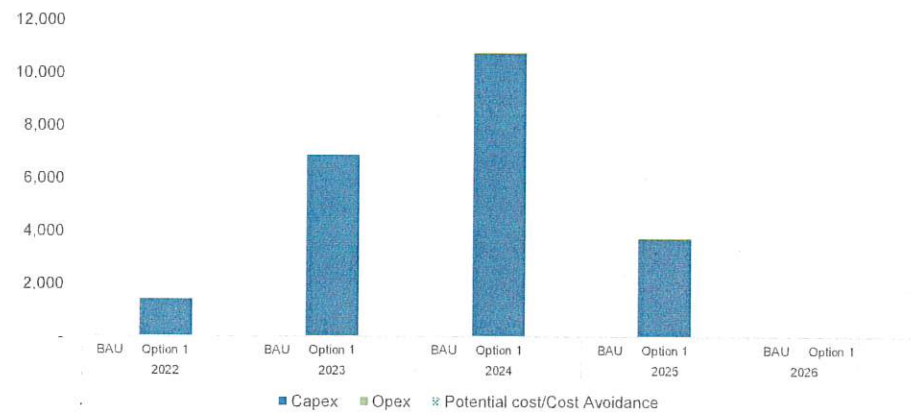
10.4 NPV Build-up Assessment

NPV buildup all options

	BAU	Option 1	Option 2
Regulated Revenue			
Return on assets	-	16,206.7	8,290.2
Regulatory Depreciation	-	7,481.1	3,826.8
Opex allowance	156.5	49.5	49.5
Efficiency Benefit	-	-	-
Tax Allowance	-	2,187.1	1,122.2
Imputation credits	-	(874.8)	(448.9)
Total Regulated Revenue	156.5	25,049.6	12,839.8
Proceeds from Sale of replaced assets	-	-	-
Unregulated Revenue	-	-	-
Opex	(156.5)	(49.5)	(49.5)
Capex	-	(20,731.6)	(10,585.1)
Tax Payable	-	(1,302.9)	(665.5)
NPV	-	2,965.4	1,539.6

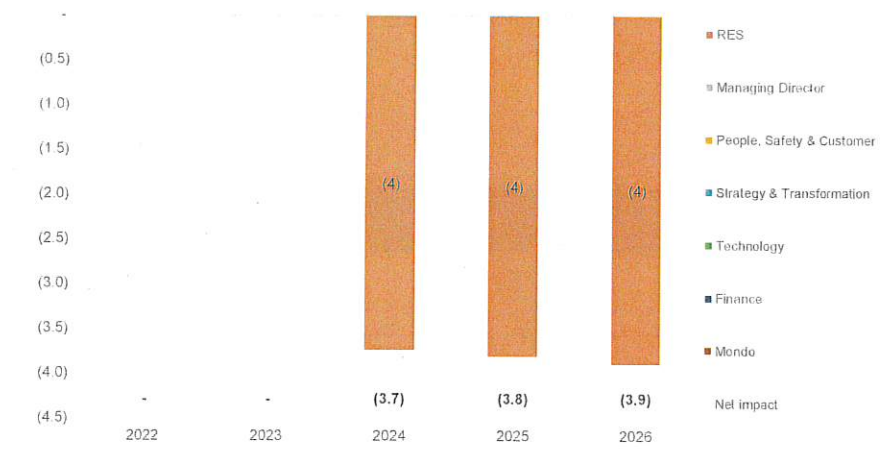
BAU vs Option 1 Least Cost Analysis - 5 year view

Nominal



Option 1 incremental budget impact compared to BAU

Nominal



11. CORPORATE ACCOUNTING CONSIDERATIONS

11.1 Asset Retirements

The project includes retirement of:

- Two 150 MVA 220/66 kV transformers (B1 & B4)
- Eight 66 kV circuit breakers
- Three 66 kV current transformers
- Poor condition assets in eight 66 kV switch bays

The total written down value (WDV) of the project is $283.5 k (WDV spread sheets are available in Appendix A6).

11.2 Contributed (Gifted) Assets

Not applicable

11.3 Assets to be created

Description of Asset	Quantity	Estimated Cost (total)	Expected Asset Life
150 MVA 220/66 kV transformers	2	$11.98 M	45 Years
66 kV circuit breakers 66 kV current transformers Associate primary equipment (earth switches, isolators etc.)	8 3	$6.1 M	45 Years
Transformer protection		$0.44M	15 Years
220 kV line protection		$1.26M	15 Years
66 kV protection (feeder protection, bus protection, cap bank protection		$1.9 M	15 Years
Other secondary (SCADA, Metering & monitoring, Comms, Digital network/asset data interface etc		1.42M	15 Years
Totals		$23.1 M	

Total Estimated Cost must match the Delivery Budget (+CFC & O/H) on page 1.

11.4 Accounting Review

Income Statement (nominal)	First 5 years					Lifecycle Total
	2022	2023	2024	2025	2026	
Regulated revenue	-	64.8	384.7	885.4	1,067.4	57,271.1
Incentive Revenue	-	-	-	-	-	-
Unregulated Revenue	-	-	-	-	-	-
Total Revenue	-	64.8	384.7	885.4	1,067.4	57,271.1
Net Opex	-	-	(1.6)	(1.6)	(1.6)	(125.8)
Net (gain) / loss on disposal of fixed assets	-	-	-	-	-	-
EBITDA	-	64.8	383.1	883.8	1,065.8	57,145.3
Depreciation	-	(31.3)	(125.0)	(355.1)	(433.3)	(22,052.2)
EBIT	-	33.4	258.1	528.7	632.5	35,093.1
Interest	-	(32.2)	(187.3)	(419.2)	(495.6)	(11,728.5)
NPBT	-	1.3	70.7	109.5	136.9	23,364.6
Tax	-	(0.4)	(21.2)	(32.9)	(41.1)	(7,009.4)
NPAT	**-**	**0.9**	**49.5**	**76.7**	**95.8**	**16,355.2**

Appendix A

A.1 Scope of works	TD-7404 ERTS2 estimate Rev.3docx.dc
A.2 Asset Management Strategy Extract	None
A.3 RIT-T PACR	East Rowville PACR_Rev4.1.pdf
A.4 Detailed Cost and Benefit Assumptions	TD-0007404 Business Case Evaluat; ERTS Stage 2 Economic Model_Rev
A.5 Asset Information	TD-0007404 Asset Information.docx
A.6 WDV	TD-7404 WDV ENG 21-01E Option 1.xlsb; TD-7404 WDV ENG 21-01E Option 2 upd