OPTIONS EVALUATION REPORT (OER)

FY24-28 KCR Secondary Systems Renewal

OER- N2444 revision 0.0

Ellipse project no(s):
TRIM file: [TRIM No]

Project reason: Capability - Asset Replacement for end of life condition
Project category: Prescribed - Replacement

Approvals

Author	Hazem Khamis	Digital Infrastructure Strategist
Endorsed	Debashis Dutta	Asset Analytics & Insights Manager
	Adam Hoare	Digital Infrastructure Asset Manager
Approved	Andrew McAlpine	A/Head of Asset Management
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Change history

Revision	Date	Amendment
0	09/11/2021	First Issue

Executive summary

Kemps Creek Substation is a part of the 500kV and 330kV backbone of the NSW Transmission Network and connects the 500kV backbone to the Metro and Southern network areas within the National Electricity Market (NEM) excluding WA and NT. The site will remain a backbone of the transmission network into the foreseeable future as outlined in the load forecasts of the 2021 Transmission Annual Planning Report (TAPR).

There is a need to address the degrading condition and increasing risk of failure associated with the secondary systems at the Kemps Creek Substation, by 2027/28. Addressing this need will ensure that TransGrid continues meeting its regulatory obligations set out in the NER.

The assessment of the options considered to address the need/opportunity appears in Table 1. A summary of all options considered are detailed below.

Under the Base Case TransGrid continues to operate and maintain (O&M) the existing site secondary systems as required. This approach will not address the obsolescence and health of the sites ageing secondary system assets.

Option A replaces all secondary system assets identified as end-of-life in a like for like approach for individual assets. This option does not leverage any technological advancements or lifecycle efficiencies within the latest design standards.

Option B renews all identified assets at the site including protection, control, metering and underlying infrastructure to leverage technological advancements in modern equipment and deliver lifecycle benefits to consumers.

Table 1 - Evaluated options ($ million)

Option	Description	Direct capital cost	Network and corporate overheads	Total capital cost[1]	Weighted NPV	Rank
Option A	Individual Asset Replacement	2.49	0.28	2.77	10.83	2
Option B	Complete In-Situ Replacement	14.86	1.65	16.51	21.95	1

It is recommended that Option B – Complete In-Situ Replacement be scoped in detail.

This option will deliver the highest net economic benefit and ensure compliance with regulatory and safety obligations.

[1] Total capital cost is the sum of the direct capital cost and network and corporate overheads. Total capital cost is used in this OER for all analysis.

1. Need/opportunity

Kemps Creek Substation comprises 2x 500kV feeders, 2x 500/330kV transformers, 3x 330kV feeders, 2x 330kV capacitors, 2x 330kV reactors, 1x SVC reactor (in-service) and 2x 33kV reactors. The site was established in 1984. The secondary systems assets have install dates between 1984 and 2020.

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Network Performance Requirements, set out in Schedule 5.1 of the NER, place an obligation on TNSPs to provide redundant protection schemes to ensure the transmission system is adequately protected. Schedule 5.1.9(c) of the NER requires a TNSP to provide sufficient primary and back-up protection systems, including any communications facilities and breaker fail protection systems, to ensure that a fault of any type anywhere on its transmission system is automatically disconnected.

Additionally, TNSPs are required to disconnect the unprotected primary systems where a secondary systems fault lasts for more than eight hours (for planned maintenance) or 24 hours (for unplanned outages). TNSPs must also ensure that all protection systems for lines at a voltage 66kV or above are well-maintained so as to be available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out[2]. In the event of an unplanned outage, AEMO's Power System Security Guidelines require that the primary network assets must be taken out of service within 24 hours[3].

Furthermore, as per clause 4.11.1 of the NER, remote monitoring and control systems are required to be maintained in accordance with the standards and protocols determined and advised by AEMO.

A failure of secondary systems would involve replacement of failed components or taking affected primary assets, such as lines and transformers, out of service.

Though replacing of failed secondary systems components is a possible interim measure, the approach is not sustainable as spare components may not be available due to supplier constraints and technological obsolescence in the future. Once manufacturer support ceases and subsequently, spares are depleted, defect repairs can no longer be a viable approach to maintain compliance with performance obligations.

The likelihood of significant secondary systems failure, and therefore not maintaining compliance with NER obligations, is anticipated to increase beyond tolerable levels once manufacturer support ceases and subsequently, available spares critical to maintaining secondary systems diminish. Based on increasing technological obsolescence and reducing levels of manufacturer support, a feasible secondary systems replacement is recommended prior to 2027/28.

Table 2 - Identified condition of secondary systems

Asset components	Issues	% of services at site
Protection Relays	> Component technology obsolescence resulting in a lack of spares and no manufacturer support > Increasing numbers of faults across a range of models > End of serviceable life	69% of all protection relays on site
Remote Monitoring	> End of serviceable life	100% of all remote

[2] As per S5.1.2.1(d) of the NER

[3] Australian Energy Market Operator. *"Power System Security Guidelines, 23 April 2019."* Melbourne: Australian Energy Market Operator, 2019. Accessed 15 May 2019. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715---Power-System-Security-Guidelines.pdf

Asset components	Issues	% of services at site
and Control Equipment	> Manufacturer support withdrawn	monitoring and control on site

Under TransGrid's Renewal and Maintenance Strategy for Infrastructure Systems[4], an opportunity exists to address these risks by performing a full secondary system replacement at the site (see risk summary in Appendix A). This opportunity arises due to the high concentration of the secondary system assets required to be addressed. It is expected that this would provide additional benefits for the consumers and the organisation including:

> Moving to a combined protection and control methodology to minimise the number of installed components and reduction in complexity. Increasing the reliability of digital assets at the site.
> Upgrading Auto Reclose facilities to allow better control, indication and fault analysis than what is currently available at the site.
> Upgrading Transformer Control facilities to allow better control, indication and fault analysis than what is currently available at the site.
> Upgrading to modern design philosophies to reduce operational and maintenance requirements at the site with the delivery of increased remote interrogation capabilities.
> Reduction in reliability consequence during failures due to consistent return to service times with standardised deployments.
> Investment will offset operational costs in corrective maintenance for unsupported technologies.

2. Related needs/opportunities

The following related Needs contain works for the site that would be fulfilled by completing a Secondary Systems Replacement:

> Need N2242 – Transmission Line Protection Renewal Program
> Need N2243 – Transformer Protection Asset Renewal Program
> Need N2244 – Reactor Protection Asset Renewal Program
> Need N2245 – Capacitor Protection Asset Renewal Program
> Need N2246 – Busbar Protection Asset Renewal Program

3. Options

3.1 Base case

The Base Case for this Need is to continue with TransGrid's current operations and maintenance (O&M) plan for the site. This approach does not address the deteriorating condition of secondary systems at the site or the risk cost associated with maintaining aging assets. The risk will likely increase due to:

> The probability of failure increasing as assets move further along their failure curves[5].
> TransGrid's inability to recover from asset failure in the future due to reducing levels of manufacturer support, and depletion of spares availability that would otherwise limit the overall consequence of asset failure.

Key drivers for this risk cost are:

[4] Refer Renewal and Maintenance Strategy – Infrastructure Systems
[5] Refer Network Asset Health Framework

- The majority of assets at this site have reached their end of technical life or have limited spares and no manufacturer support as highlighted in previous sections. This therefore increases the likelihood of a hazardous event occurring and decreases TransGrid's ability to mitigate or repair failures.
- Assets have increasing numbers of failure as they progress along their failure curves, degrading components or are prone to mechanical wear, increasing the likelihood of a hazardous event occurring.

Increasing maintenance on secondary systems equipment cannot reduce the probability of failure or reduce risk costs. This is because maintenance of secondary assets is focused on device inspection and functional performance checks only, the conduct of maintenance at an electronic component level is neither feasible nor practicable.

3.2 Options evaluated

Option A — Replace Individual Assets [NOSA N2444, OFS N2444A]

This option involves individual replacements of identified assets up to 2027/28. The option is based on a like-for-like approach whereby the asset is replaced by its modern equivalent. Additional system modifications or additional functionalities would not be deployed under this option. This option will lock TransGrid to a system architecture that cannot be expanded to match modern technology capabilities into the future.

This option would deliver the least benefits to consumers and the network by only affecting the probability of failure of targeted assets. This option will not provide any additional operational benefits such as improved capabilities for remote interrogation and predictive activities.

This option is planned for deployment across the 2023/24-2027/28 regulatory control period with remaining assets at the site to incur investment in future years. Targeted assets will be in service for approximately 15 years.

Option B — Complete In-Situ Replacement [NOSA N2444, OFS N2444B]

This option involves replacement of all secondary systems assets at the site. This option will modernise the automation philosophy to current design standards and practices. This option also includes replacement of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415V Alternating Current (AC) distribution in the building and the switchyard.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, DC supply systems, and market meters creates a need for modernisation. This will deliver benefits such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing.

There are also additional operational benefits available due to improved remote monitoring, control and interrogation, efficiency gains in responding to faults, and phasing out of obsolete and legacy systems and protocols.

3.3 Options considered and not progressed

Table 3 - Options not progressed

Option	Reason for not progressing
Complete SSB Replacement	Whilst this option is technically feasible, it requires the installation of new cabling and buildings. Based on the 2020 building dilapidation report and no noted rise in cable defects, the condition of these assets on site does not support their replacement. Further details on this decision can be found in the FY24-28 Option Screening Report - Secondary System Renewals.

Option	Reason for not progressing
Upgrade to IEC61850	Whilst this option is technically feasible, it requires the installation of new cabling and buildings. Based on the 2020 building dilapidation report and no noted rise in cable defects, the condition of these assets on site does not support their replacement. Further details on this decision can be found in the FY24-28 Option Screening Report - Secondary System Renewals.
Asset Retirement	This can only be achieved by retiring the associated primary assets, which is not technically or economically feasible. This site will remain an essential connection point into the foreseeable future as detailed within TransGrid's 2021 TAPR.
Non-network solutions	It is not technically feasible for non-network solutions to provide the functionality of secondary systems assets for protection, control, communications and metering

4. Evaluation

4.1 Commercial evaluation methodology

The economic assessment undertaken for this project includes three scenarios that reflect a central set of assumptions based on current information that is most likely to eventuate (central scenario), a set of assumptions that give rise to a lower bound for net benefits (lower bound scenario), and a set of assumptions that give rise to an upper bound on benefits (higher bound scenario).

Assumptions for each scenario are set out in the table below.

Table 4 – Scenario assumptions

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Discount rate	4.8%	7.37%	2.23%
Capital cost	100%	125%	75%
Operating expenditure benefit	100%	75%	125%
Risk costs benefit	100%	75%	125%
Benefits	100%	75%	125%
Scenario weighting	**50%**	**25%**	**25%**

Parameters used in this commercial evaluation are shown in Table 5.

Table 5 - Commercial evaluation parameters

Parameter	Parameter Description	Value used for this evaluation
Discount year	Year that dollar values are discounted to	2020/21
Base year	The year that dollar value outputs are expressed in real terms	2020/21 dollars

Parameter	Parameter Description	Value used for this evaluation
Period of analysis	Number of years included in economic analysis with remaining capital value included as terminal value at the end of the analysis period.	15 years
Safety disproportionality	Multiplier of the safety risk cost included in NPV analysis to demonstrate implementation of obligation to reduce safety to ALARP.	Refer to section 4.3 for details.

The capex figures in this OER do not include any real cost escalation.

4.2 Commercial evaluation results

The commercial evaluation of the technically feasible options is set out in Table 6. Details appear in Appendix A.

Table 6 - Commercial evaluation ($ million)

Option	Capital Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option A	10.96	9.16	0.00	25.01	10.83	2
Option B	13.59	19.36	2.60	46.48	21.95	1

4.3 ALARP evaluation

TransGrid manages and mitigates bushfire and safety risk to ensure they are below risk tolerance levels or ‘As Low As Reasonably Practicable’ (‘ALARP’), in accordance with the regulation obligations and TransGrid’s business risk appetite. Under the Electricity Supply (Safety and Network Management) Regulation 2014 Section 5 ‘A network operator must take all reasonable steps to ensure that the design, construction, commissioning, operation and decommissioning of its network (or any part of its network) is safe.’ TransGrid maintains an Electricity Network Safety Management System (ENSMS) to meet this obligation[6].

In its Network Risk Assessment Methodology, under the ALARP test with the application of a gross disproportionate factor[7], the weighted benefits are expected to exceed the cost. Where TransGrid’s analysis concludes that the costs are less than the weighted benefits from mitigating bushfire and safety risks, the proposed investment will enable TransGrid to continue to manage and operate this part of the network to a safety and risk mitigation level of ALARP.

Evaluation of the above options has been completed in accordance with As Low As Reasonably Practicable (ALARP) obligations. The Network Safety Risk Reduction is calculated as 6 x Bushfire Risk Reduction + 6 x Safety Risk Reduction + 3 x other Environmental Risk Reduction + 0.1 x Reliability Risk Reduction.

Results of the ALARP evaluation are set out in Table 7.

[6] TransGrid’s ENSMS follows the International Organization for Standardization’s ISO31000 risk management framework which requires following hierarchy of hazard mitigation approach

[7] In accordance with the framework for applying the ALARP principle, a disproportionality factor of 6 has been applied to risk cost figures. The values of the disproportionality factors were determined through a review of practises and legal interpretations across multiple industries, with particular reference to the works of the UK Health and Safety Executive. The methodology used to determine the disproportionality factors in this document is in line with the principles and examples presented in the AER Replacement Planning Guidelines and is consistent with TransGrid’s Revised Revenue Proposal 2023/24- 2027/28.

Table 7 - Reasonably practicable test ($ million)

Option	Network Safety Risk Reduction	Annualised Capex	Reasonably Practicable?[8]
A	2.42	0.26	Yes
B	2.26	1.57	Yes

The result of the ALARP evaluation is that both options meets ALARP.

4.4 Preferred option

The preferred option to meet the identified need by 2027/28 is Option B. Option B is the most prudent and economically efficient solution to enable TransGrid to continue meeting its regulatory obligations set out in clauses 4.11.1, 4.6.1(b),[9] and Schedule 5.1 of the NER. This option maximises net economic benefits to all those who produce, consume and transport electricity in the market, and will ensure performance standards applicable to the site's secondary systems continue to remain met.

Option B involves an on-site renewal (replacement) of the individually assessed components in an old for new replacement. Efficiencies will be achieved by reusing the existing building, tunnel boards, and the cabling where practicable.

Capital and Operating Expenditure

There is negligible difference in predicted ongoing planned routine operational expenditure between the option and the Base Case. The removal of Nickel Cadmium systems and their associated infrastructure will deliver savings regarding battery and room maintenance activities.

Resultant corrective maintenance under the base case strategy will result in higher medium to long term expenditure. Delivery of proposed works under Option B will reduce the risk of increasing direct defect response costs.

It has been modelled that those components with no manufacturer support and limited spares carry the potential for incurring aspects of the proposed capital expenditure as operational expenditure. In such a scenario, these higher costs are attributable to significant design and preparation costs, and likely augmentation of linking systems required to move a system from one design solution to a differing solution. Such costs would not be present in cases where a like-for-like replacement is feasible.

These operating expenditure benefits have been captured in the economic evaluation.

Regulatory Investment Test

The program and estimate allows for the appropriate Regulatory approvals as required.

5. Optimal Timing

The test for optimal timing of the preferred option has been undertaken. The approach taken is to identify the optimal commissioning year for the preferred option where net benefits (including avoided costs and safety disproportionality tests) of the preferred option exceeds the annualised costs of the option. The commencement year is determined based on the required project disbursement to meet the commissioning year based on the OFS.

The results of optimal timing analysis are:

> Optimal commissioning year: 2026/27

[8] Reasonably practicable is defined as whether the annualised CAPEX is less than the Network Safety Risk Reduction.

[9] As per clause 4.6.1(b) of the NER, AEMO must ensure that there are processes in place, which will allow the determination of fault levels for normal operation of the power system and in anticipation of all credible contingency events and protected events that AEMO considers may affect the configuration of the power system, so that AEMO can identify any busbar which could potentially be exposed to a fault level which exceeds the fault current ratings of the circuit breakers associated with that busbar.

- Commissioning year annual benefit: $2.99 million
- Annualised cost: $1.57 million

The project is expected to commence in the 2023/24-2027/28 Regulatory Period based on the optimal timing.

6. Recommendation

It is the recommendation that Option B – Complete In-Situ Replacement be scoped in detail.

The total project cost is $16.51 million including $1.50 million to progress the project from DG1 to DG2.

Appendix A – Option Summaries

Table 8 - Option A Summary Analysis

Project Description	**FY24-28 KCR SSR**		
Option Description	Option A - Individual Asset Replacement		
Project Summary			
Option Rank	*2*	Investment Assessment Period	*15*
Asset Life	*15*	NPV Year	2020/21
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	9.16	Annualised CAPEX @ Central Benefit Scenario ($m)	Annualised Capex - Standard (Business Case) 0.26
NPV @ Lower Bound Scenario (PV, $m)	0.00	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction 2.42
NPV @ Higher Bound Scenario (PV, $m)	25.01	ALARP	ALARP Compliant? Yes
NPV Weighted (PV, $m)	10.83	Optimal Timing	Optimal timing (Business Case) 2023/24
Cost (Central Scenario)			
Total Capex ($m)	2.77	Cost Capex (PV,$m)	10.96
Terminal Value ($m)	0.00	Terminal Value (PV,$m)	0.00
Risk (Central Scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) 4.04	Reliability Risk (Post) 2.63	Pre – Post 1.41
Financial (PV,$m)	Financial Risk (Pre) 8.99	Financial Risk (Post) 6.52	Pre – Post 2.47
Operational/Compliance (PV,$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,$m)	Safety Risk (Pre) 0.06	Safety Risk (Post) 0.04	Pre – Post 0.02
Environmental (PV,$m)	Environmental Risk (Pre) 42.11	Environmental Risk (Post) 27.59	Pre – Post 14.52
Reputational ($m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk (PV,$m)	Total Risk (Pre) 55.20	Total Risk (Post) 36.78	Pre – Post 18.42
OPEX Benefit (PV,$m)			OPEX Benefit 0.00
Other benefit (PV,$m)			Incremental Net Benefit 0.93
Total Benefit (PV,$m)			Business Case Total Benefit 20.11

Table 9 - Option B Summary Analysis

Project Description	**FY24-28 KCR SSR**		
Option Description	Option B - Complete In-Situ Replacement		
Project Summary			
Option Rank	*1*	Investment Assessment Period	*15*
Asset Life	*15*	NPV Year	2020/21
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	19.36	Annualised CAPEX @ Central Benefit Scenario ($m)	Annualised Capex - Standard (Business Case) 1.57
NPV @ Lower Bound Scenario (PV, $m)	2.60	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction 2.26
NPV @ Higher Bound Scenario (PV, $m)	46.48	ALARP	ALARP Compliant? Yes
NPV Weighted (PV, $m)	21.95	Optimal Timing	Optimal timing (Business Case) 2023/24
Cost (Central Scenario)			
Total Capex ($m)	16.51	Cost Capex (PV,$m)	13.59
Terminal Value ($m)	0.00	Terminal Value (PV,$m)	0.00
Risk (Central Scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) 4.04	Reliability Risk (Post) 2.54	Pre – Post 1.50
Financial (PV,$m)	Financial Risk (Pre) 8.99	Financial Risk (Post) 5.20	Pre – Post 3.79
Operational/Compliance (PV,$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,$m)	Safety Risk (Pre) 0.06	Safety Risk (Post) 0.03	Pre – Post 0.03
Environmental (PV,$m)	Environmental Risk (Pre) 42.11	Environmental Risk (Post) 27.46	Pre – Post 14.65
Reputational ($m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk (PV,$m)	Total Risk (Pre) 55.20	Total Risk (Post) 35.23	Pre – Post 19.96
OPEX Benefit (PV,$m)			OPEX Benefit 0.05
Other benefit (PV,$m)			Incremental Net Benefit 12.19
Total Benefit (PV,$m)			Business Case Total Benefit 32.95