OPTIONS EVALUATION REPORT (OER)

Tenterfield Transformer Renewals

OER- N2424 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

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Change history

Revision	Date	Amendment
00	10/11/2021	Initial

Executive summary

Power transformers are essential for the safe and reliable electricity transmission as they enable different voltage levels throughout the transmission and distribution networks. As part of the condition assessment and health index methodology, Tenterfield No.1 and No.2 132kV transformers have been identified as reaching end of life and with an increasing risk of failure. The need of this project is economic benefit, with risks which will require remediation within the 2023 – 2028 regulatory period.

Tenterfield 132kV Substation is located in Transgrid's Northern NSW network. It connects to Transgrid's 132 kV Glen Innes and Lismore substations. It also connects the Essential Energy 22kV distribution network supplying the Tenterfield region.

The No.1 and No.2 Transgrid transformers at Tenterfield Substation were commissioned in 1968 and they have now reached end of their serviceable life. The health index considers natural age, dissolved gas analysis (DGA), oil quality (OQ), Bushing DDF, defects, load and corrosive oil.

The No.1 and No.2 transformers are showing signs of deterioration due to the following key factors:

> Natural Age: The transformer will be 55 years in 2022/23 which is well above the 45-year expected useful life of a power transformer.
> Corrosive Sulphur: The insulating oil has corrosive sulphur, which can form conductive compounds on the insulation paper and tap changer contacts. This can cause an internal flashover and could lead to a catastrophic failure.
> Internal Arcing: Dissolved Gas Analysis (DGA) shows high levels of Acetylene in the main tank of the transformer. This typically indicates arcing in the paper or oil at high temperatures.
> Oil leaks: There are leaks from the valves and main tank lid gasket, allowing moisture ingress and oxygen into the main insulation.

These condition issues have been evaluated through the transformer health index methodology to give an effective age of 61 years for both No.1 and No.2 Transformer (2022/23). These condition issues, if not remediated, increase the probability of transformer failure. The replacement of the Tenterfield transformers would significantly reduce the likelihood of prolonged and involuntary load shedding in the Northern region and help Transgrid manage its safety obligations.

The key economic benefits associated with addressing this need are summarised as:

> Reduction of risk as valued as a direct impact to Transgrid and consumers including:
  – Changes in involuntary load shedding
  – Safety and environmental hazards associated with a catastrophic failure.
> Avoided operating expenditure related to corrective maintenance;

Two options have been considered to address the increasing risk of failure of the Tenterfield transformers, as shown in Table 1 below. These options are the complete replacement of the two transformers with new units (option A) and refurbishment of the existing transformers involving replacement of bushings attempting to address the identified condition issues (option B).

The preferred option is the replacement of the Tenterfield No.1 and No.2 Transformers (option A). This option is technically feasible and has the highest Net Present Value. The option is optimally timed to be completed across the 2023-2028 and 2028-33 regulatory periods.

Table 1 - Evaluated options ($ million)

Option	Description	Direct	Network and	Total capital	Weighted	Rank

		capital cost	corporate overheads	cost[1]	NPV	
Option A	Replacement	9.96	1.03	10.99	3.00	1
Option B	Refurbishment	1.23	0.45	1.68	1.13	2

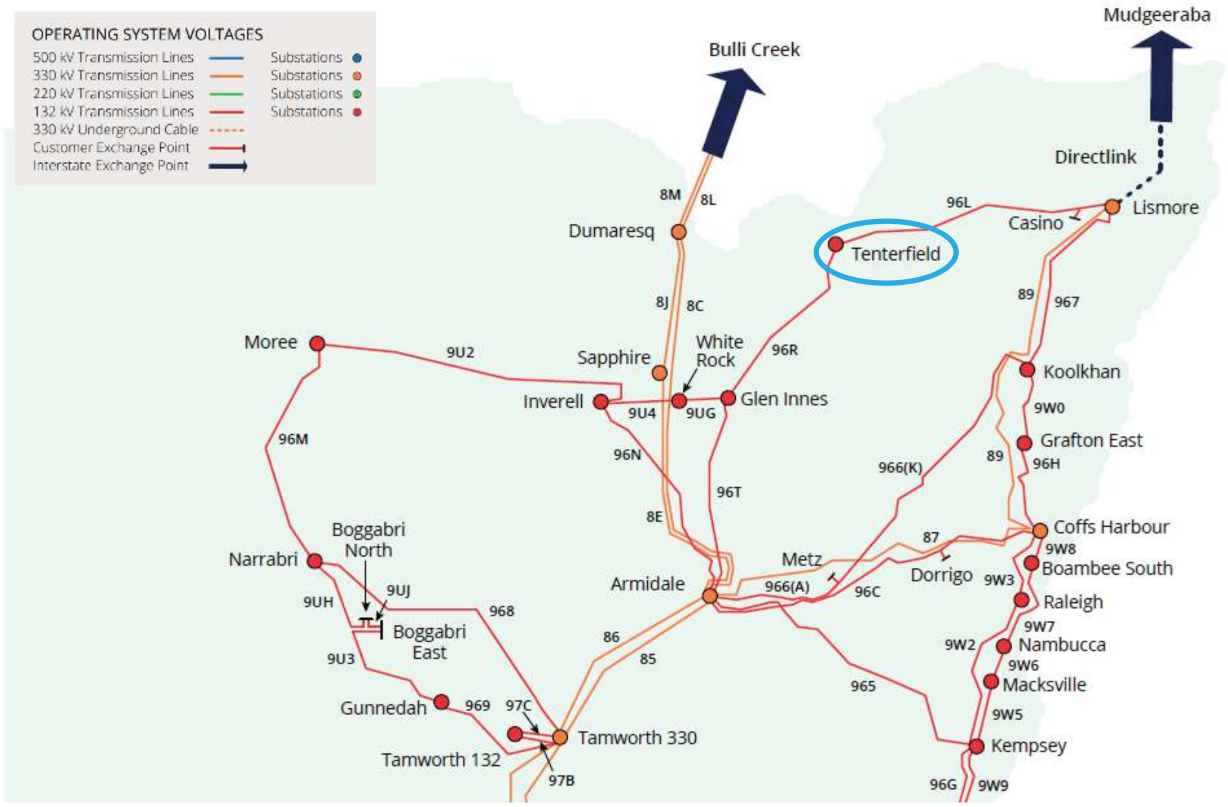
1. Need/opportunity

Tenterfield 132/22 kV Substation was commissioned in 1968 and forms part of Transgrid's Northern NSW network that serves the New England region. Tenterfield substation connects 132 kV transmission lines 96R to Glen Innes and Line 96L to Lismore.

The location of Tenterfield Substation and supply arrangements for the Northern NSW network is provided in As a customer connection point supplying Essential Energy in the Tenterfield area, Tenterfield substation supports the flow of electricity to local industries and the residential population.

Figure 1 below. As a customer connection point supplying Essential Energy in the Tenterfield area, Tenterfield substation supports the flow of electricity to local industries and the residential population.

Figure 1: Northern NSW transmission network



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[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.

Note: The 22kV Essential Energy network that Tenterfield Substation supplies is not shown in **Figure 1**.

The Tenterfield No.1 and No.2 Transformers (132/22kV, 15MVA each) were commissioned in 1968 during the initial construction of Tenterfield Substation. The transformers at the substation plays a central role in supplying electricity to the Essential Energy distribution network.

The two transformer arrangement allows for an N-1 contingency during planned and unplanned outages. Transgrid does not have an agreed back up arrangement for the Tenterfield load with Essential Energy network.

Condition Assessment of the Tenterfield Transformers using Transgrid's Network Asset Risk Assessment Methodology (RAM) has noted signs of deterioration, primarily due to condition issues set out in Table 2 below.

Table 2 - Condition Issues

Issue	Potential impact
Corrosive Sulphur	Corrosive sulphur can form conductive compounds on insulating paper, disrupting the integrity of the paper leading to thermal insulation failure or electrical breakdown between adjacent conductors. Sulphur compounds can also attack the silver coating on selector switching contacts, creating loose sections of conductive silver sulphide. This can result in a catastrophic failure of the tap changer and/or transformer.
Internal Arcing	Dissolved Gas Analysis (DGA) shows high levels of Acetylene (C_2H_2) in the main tank of the transformer. This typically indicates arcing in the paper or oil at high temperatures above 1000 °C. Acetylene levels have been increasing over time indicating the fault is still active. Leakage from the tap changer compartment to the main tank can also cause elevated levels of Acetylene. There was no evidence of this occurring during the previous internal inspection. Lighter combustible gases are relatively low, indicating losses to the atmosphere through leaks. Long term treading and analysis is ineffective as the oil has been filtered and treated during previous refurbishments.
Loss of oil due to leaks	Flange and gasket leaks can cause loss of oil within the Transformer resulting in a catastrophic failure. Moisture and oxygen can also enter the transformer resulting in accelerated aging of the insulation resulting in failure.

If the deteriorating asset condition is not addressed by a technically and commercially feasible option, the likelihood of prolonged and involuntary load shedding in the Tenterfield region will increase.

In addition, the increased risk of failure presents a safety risk which Transgrid is obligated to manage. Rectifying the worsening condition of the transformer will reduce safety risks, as well as lower planned and unplanned corrective maintenance costs.

The key economic benefits associated with addressing this need are summarised as:

- Reduction of risk as valued as a direct impact to Transgrid and consumers including:
  - Changes in involuntary load shedding
  - Safety and environmental hazards associated with a catastrophic failure.
- Avoided operating expenditure related to corrective maintenance;

2. Related needs/opportunities

Generation connections are planned for the Tenterfield region which could increase the capacity of the transformers from 15MVA to 30MVA. Uprating requirements shall be further assessed by Network Planning during detailed development.

3. Options

3.1 Base case

Under the 'Base Case' scenario, there is no consideration for planned replacement of the transformer. This is a 'run to fail' scenario and will lead to an increase in the identified risks, the transformer's eventual failure, and the materialisation of the expected consequences. This case shall only be considered as a last resort should no option be deemed viable through the economic evaluation process.

Replacement of a failed transformer is expensive and requires significant time to restore capacity. Key considerations against the base case are:

> Transgrid holds an onsite like-for-like spare for the Tenterfield No.1 and No.2 transformer.
> Due to the condition of the spare transformer, the transformer will require major refurbishment:
  – Leak repairs, major maintenance and corrosion treatment.
  – Replacement of any out of tolerance bushings prior to energisation.
  – A major overhaul of the tap changer and selector to confirm that the unit is in serviceable condition.
  – Oil treatment and/or replacement based on moisture content
> If the failure is catastrophic, there is substantial clean up and disposal costs and likely to take 1-2 weeks.
> The spare transformer will need to undergo high voltage testing and commissioning works.

3.2 Options evaluated

Option A — Replacement of No.1 and No.2 Transformers [NOSA 2424, OFS 2424A]

This option replaces both transformers with new 132/22 kV 15 MVA transformers. The option will address the identified need by installing new transformers with a very low probability of failure, associated risks and lower operating costs.

This option involves:

> Installation of two new 15MVA power transformers
> Relocation of the spare transformer and demolition of the spare transformer compound
> Installation of new switch bays, gantries, busbar extension, protection and control systems (secondary systems);
> Bench extension, modifications of two transformer compounds and palisade fencing;
> Installation of the No.1 auxiliary transformer;
> Construction of new firewalls for each transformer;

Staging of works requires the installation of a new No.3 transformer prior to decommissioning the No.1 and No.2 transformer to maintain reliability during construction.

The estimated Capex for this option is $10.99 million, comprising of $7.23 million for No.2 Transformer replacement and $3.76 million for No.1 Transformer replacement. The new transformers have an expected asset life of 45 years and the expected project timeframe from Decision Gate 1 (DG1) is 38 months.

Option B — Refurbishment of No.1 and No.2 Transformers [NOSA 2424, OFS 2424B]

This option consists of an in-situ refurbishment of the Tenterfield No.1 and No.2 Transformers according to the recommended scope in Network Asset Condition Assessment (NACA):

> Corrosion repair, leak repair and repainting;
> Conservator modifications and/or repairs.

The No.1 and No.2 transformers have had 132kV bushing replacements in 2010 and a major refurbishment in 2017, the refurbishment under this need is only expected to result in a reduction of four years, limited by the natural age of the transformer. While refurbishment will remediate some of the condition issues, it will not improve the quality of the paper insulation and ageing in the core of the transformer.

The majority of reliability, safety and environmental risk will remain even after the refurbishment and will only be addressed by replacement. The refurbishment option will essentially delay the transformer replacement into 2028 – 2033 regulatory period.

The estimated Capex with for option is $1.68 million, comprising of $0.84 million for No.1 Transformer refurbishment and $0.84 million for No.2 Transformer refurbishment, with an expected improvement of asset life of four years. The expected project timeframe from DG1 is 21 months.

3.3 Options considered and not progressed

The following options were considered but not progressed:

Table 3 - Options not progressed

Option	Reason for not progressing
Increased maintenance or inspections	The condition issues have already been identified and cannot be rectified through increased maintenance or inspections, and therefore is not technically feasible to address the need.
Elimination of all associated risk	This can only be achieved by retiring the assets, which is not technically feasible due to the requirement to maintain the existing network reliability.
Non-network solutions	Transgrid does not consider non-network options to be commercially feasible to assist with meeting the identified need.

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 Table 4.

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 cost benefits	100%	75%	125%
Other Benefits	Not applicable in this assessment		
Scenario weighting	**50%**	**25%**	**25%**

Parameters used in this commercial evaluation are in Table 5

Table 5 - Commercial evaluation parameters

Parameter	Parameter Description	Value used for this evaluation
Discount year	The 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
Period of analysis	The number of years included in economic analysis with remaining capital value included as terminal value at the end of the analysis period.	25 years
ALARP disproportionality	Multiplier of the environmental and safety related risk cost included in NPV analysis to demonstrate implementation of the obligation to reduce 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 (PV, $ million)

Option	Capital Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking

Option	Capital Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option A	9.33	2.00	-4.53	12.53	3.00	1
Option B	1.43	0.93	-0.36	3.03	1.13	2

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.[2]

In its Network Risk Assessment Methodology, under the ALARP test with the application of a gross disproportionate factor[3], the weighted benefits are expected to exceed the cost. 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 + 3 x Safety Risk Reduction + 3 x Other Environmental Risks + 0.1 x Reliability Risk Reduction.

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

Table 7 - Reasonably practicable test ($ million)

Option	Network Safety Risk Reduction	Annualised Capex	Reasonably Practicable?[4]
A	0.10	0.60	No
B	0.02	0.16	No

The result of the ALARP evaluation is that all options lie under the ALARP threshold.

4.4 Preferred option

The preferred option is the replacement (Option A) of the Tenterfield No.1 and No.2 Transformers, as this is technically feasible and has the highest positive NPV. This option addresses the need by achieving the largest risk reduction. A new transformer has a relatively low probability of failure (PoF) and corresponding post-investment risk.

Capital and Operating Expenditure

Opex benefits associated with avoided corrective and reduced routine expenditure have been included in the business case NPV and optimal timing evaluation.

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[2] Transgrid's ENSMS follows the International Organization for Standardization's ISO31000 risk management framework which requires following hierarchy of hazard mitigation approach

[3] 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.

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

There are no capex to opex trade-offs considered in this evaluation.

Regulatory Investment Test

A Regulatory Investment Test for Transmission (RIT-T) is expected to be required as the preferred option is above $6 million.

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: 2028/29
- Commissioning year annual benefit: $0.61 million
- Annualised cost: $0.60 million

Based on the optimal timing and a project duration of 38 months, the project shall be completed across the 2023-2028 and 2028-2033 Regulatory Periods, with the majority of expenditure expected to occur in the 2023-2028 regulatory period.

6. Recommendation

It is recommended that Option A for the replacement of the transformers be scoped in detail.

The total project cost is $10.99 million, including $1 million to progress the project from DG1 to DG2.

Appendix A – Option A Summary

Project Description	Tenterfield Transformer Renewals		
Option Description	Option A - Transformer Replacement		
Project Summary			
Option Rank	*1*	Investment Assessment Period	*25*
Asset Life	*45*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *2.00*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) *0.60*
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] *-4.53*	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction *0.10*
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] *12.53*	ALARP	ALARP Compliant? *No*
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *3.00*	Optimal Timing	Optimal timing (Business Case) *2029*
Cost			
Direct Capex ($m)	*9.96*	Network and Corporate Overheads ($m)	*1.03*
Total Capex ($m)	*10.99*	Cost Capex (PV,$m)	*9.33*
Terminal Value ($m)	*4.64*	Terminal Value (PV,$m)	*1.19*
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *8.63*	Reliability Risk (Post) *0.48*	Pre – Post *8.15*
Financial (PV,$m)	Financial Risk (Pre) *1.33*	Financial Risk (Post) *0.16*	Pre – Post *1.17*
Operational/Compliance (PV,$m)	Operational Risk (Pre) *0.00*	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *0.52*	Safety Risk (Post) *0.06*	Pre – Post *0.46*
Environmental (PV,$m)	Environmental Risk (Pre) *0.33*	Environmental Risk (Post) *0.04*	Pre – Post *0.29*
Reputational ($m)	Reputational Risk (Pre) *0.07*	Reputational Risk (Post) *0.01*	Pre – Post *0.06*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *10.88*	Total Risk (Post) *0.76*	Pre – Post *10.12*
OPEX Benefit (PV,$m)			OPEX Benefit *0.01*
Other benefit (PV,$m)			Incremental Net Benefit *0.00*
Total Benefit (PV,$m)			Business Case Total Benefit *10.14*

Appendix B – Option B Summary

Project Description	Tenterfield Transformer Renewals		
Option Description	Option B - Transformer Refurbishment		
Project Summary			
Option Rank	*2*	Investment Assessment Period	*25*
Asset Life	*15*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *0.93*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) 0.16
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] -0.36	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction 0.02
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] 3.02	ALARP	ALARP Compliant? No
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *1.13*	Optimal Timing	Optimal timing (Business Case) 2031
Cost			
Direct Capex ($m)	*1.23*	Network and Corporate Overheads ($m)	*0.45*
Total Capex ($m)	*1.68*	Cost Capex (PV,$m)	*1.43*
Terminal Value ($m)	*0.00*	Terminal Value (PV,$m)	*0.00*
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *8.63*	Reliability Risk (Post) *6.57*	Pre – Post *2.06*
Financial (PV,$m)	Financial Risk (Pre) *1.33*	Financial Risk (Post) *1.17*	Pre – Post *0.16*
Operational/Compliance (PV,$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *0.52*	Safety Risk (Post) *0.46*	Pre – Post *0.06*
Environmental (PV,$m)	Environmental Risk (Pre) *0.33*	Environmental Risk (Post) *0.29*	Pre – Post *0.04*
Reputational ($m)	Reputational Risk (Pre) 0.07	Reputational Risk (Post) *0.07*	Pre – Post *0.00*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *10.88*	Total Risk (Post) *8.55*	Pre – Post *2.34*
OPEX Benefit (PV,$m)			OPEX Benefit *0.01*
Other benefit (PV,$m)			Incremental Net Benefit *0.00*
Total Benefit (PV,$m)			Business Case Total Benefit *2.35*